PART A. INTRODUCTION/OVERVIEW

A.1 INTRODUCTION/BACKGROUND

The Proposed Project for this study is the construction, operation, and maintenance of the Alturas Transmission Line, as proposed by Sierra Pacific Power Company (SPPCo or Applicant). The Applicant's Proposed Project would extend a 345,000 volt (345 kV) overhead electric power transmission line approximately 165 miles from Alturas, California, to Reno, Nevada. The proposal also includes the construction of two new electrical substations, one northwest of Alturas, California, and one just west of Border Town, California, near the California-Nevada state line. The existing SPPCo North Valley Road Substation in Reno would be improved to allow for the tie-in of the new 345 kV line. The Proposed Project would also require a two-mile, 230 kV transmission line from the interconnection point with the Bonneville Power Administration's existing 230 kV line to the Alturas Substation.

The Lead Federal and State Agencies responsible for preparing this Environmental Impact Report/ Statement for the Proposed Project are the U.S. Department of the Interior, U.S. Bureau of Land Management (BLM), and the California Public Utilities Commission (CPUC), respectively. On February 8, 1993, SPPCo submitted a preliminary application to the BLM for a right-of-way for the Alturas Transmission Line Project. On April 19, 1993, the BLM notified SPPCo that the completion of an Environmental Impact Statement (EIS), in accordance with the National Environmental Policy Act (NEPA), would be required to process the application.

On November 9, 1993, SPPCo filed an application with the CPUC for a Certificate of Public Convenience and Necessity (CPCN) to construct and operate the Alturas Transmission Line Project. In response to subsequent requests from the CPUC, SPPCo filed supplemental information on January 19 and February 10, 1994. The CPUC accepted SPPCo's application as complete on February 14, 1994, and informed the Applicant that an Environmental Impact Report (EIR), in accordance with the California Environmental Quality Act (CEQA), would be required to process the application. Pursuant to Rule 17.1 of the CPUC Rules of Practice and Procedure, SPPCo also submitted a Proponent's Environmental Assessment (PEA) for the Proposed Project, dated October 1993. SPPCo filed additional supplemental information on May 27, 1994, and amended its application on October 4, 1994.

As stated above, the CPUC and BLM are the lead State and Federal agencies for compliance with CEQA and NEPA, respectively. The purpose of this joint CEQA/NEPA document, referred to as the EIR/S, is to assess the potential environmental impacts that would result from the construction, operation, and maintenance of the Alturas Transmission Line. The impact analysis is accompanied by the identification of feasible mitigation measures which, if incorporated into the project, would avoid or minimize impacts. This EIR/S also assesses alternatives to the Proposed Project and identifies and analyzes those with the potential to further eliminate or minimize impacts. This document was prepared under the direction of the CPUC and BLM, and is provided for review by the public and by government agencies as required under provisions of CEQA and NEPA.

This document considers comments made by agencies and the public during the scoping period, which began with the issuance of the Notice of Preparation/Notice of Intent on March 17, 1994, and continued through May, 1994. During the scoping process, the CPUC and the BLM conducted four public meetings to receive input on the environmental issues associated with the Proposed Project and the alternatives that should be considered.

On March 3, 1995, the Draft EIR/S was released for a 60-day comment period and the public was invited to comment on the document. Four public workshops to present the document were held in March 1995. Based on requests from the public, the comment period was extended an additional 30-days to June 2, 1995. Written comments directed to the Lead Agencies were received, and four public hearings were held in April 1995 to receive oral and written comments. This Final EIR/S, which will be circulated to the public, responds to the comments received with both specific responses to each comment received, and text modifications and/or additions (text changes/additions are denoted by bars in the right margin, with the exception of new sections such as Responses to Comments [Part H], Appendices E.6 - E.10, and C.14, Impacts on Minority and Low-Income Communities). Table A-1 summarizes the public participation process for this EIR/S.

A.2 READER'S GUIDE TO THIS DOCUMENT

This EIR/S is organized as follows:

VOLUME I - MAIN DOCUMENT

Executive Summary: A summary description of the Proposed Project, Project alternatives, and their environmental impacts. Impact Summary Tables are provided that tabulate the impacts and mitigation measures for the Proposed Project and alternative scenarios.

Part A (Introduction/Overview): An overview of the public agency use of the EIR/S and a discussion of the purpose and need for the project.

Part B (Project and Alternative Descriptions): Detailed descriptions of the proposed Alturas Transmission Line Project, the alternatives considered but eliminated from further analysis, the alternative projects and alignments analyzed in Part C, and the scenario used for the analysis of cumulative impacts.

Part C (Environmental Analysis): A comprehensive analysis and assessment of impacts and mitigation measures for the Proposed Project, cumulative scenario, the No Project Alternative, and alternative projects. This part is divided into main sections for each environmental issue area (e.g., Air Quality, Biology, Geology, etc.) which contain the environmental setting, impacts, and cumulative effects of the Proposed Project and each alternative. Resource data collected for each issue area were entered into a Geographic Information System and are illustrated on the project base maps (see end of Volume I). At the end of each issue area analysis, a detailed Mitigation Monitoring Program is provided.

Table A-1 EIR/S Public Participation Process Summary

Date	Item
March 17, 1994	Notice of Preparation (NOP) of Draft EIR issued by the CPUC*
March 30, 1994	Notice of Intent (NOI) to prepare a Draft EIS issued by the BLM*
April 1994	Notice of Public Scoping Meetings published in the following local newspapers: • Lassen County Times • The Mountain Messenger • Modoc County Record • Reno Gazette Journal
April 24, 1994	NOI published in the Federal Register
May 17- 25, 1994	Public scoping meetings to determine the scope of the EIR/S held in Susanville, Alturas, Reno/Sparks, and Loyalton area
May 27, 1994	End of public scoping period/scoping comments due (see Appendix B, Scoping Report for resutls)*
January 27, 1995	Project Newsletter mailed out to project mailing list (1400 people)
February 28 - March 12, 1995	Publication dates for notice on release of Draft EIR/S, Informational Workshops and Public Hearings in: • Lassen County Times • Reno Gazette Journal • Modoc County Record • The Sacramento Bee • The Mountain Messenger
March 3, 1995	Draft EIR/S released for public review* • Notice of Completion of the EIR/S issued by the CPUC • Notice of release of Draft EIR/S/Notice of Informational Workshops and Public Hearings sent to property owners within 600 feet of the transmission line
March 9, 1995	Notice of Availability of Draft EIR/S issued by the EPA and BLM and published in the Federal Register
March 13 - 16, 1995	Informational Workshops on the Draft EIR/S in Alturas, Susanville, Loyalton, and Reno/Sparks area
April 17 - 20, 1995	Public Hearings on the Draft EIR/S in Alturas, Susanville, Loyalton, and Reno/Sparks area
April 27, 1995	Notice of 30-day Extension of Draft EIR/S Public Review Period mailed out to project mailing list (1700 people)
April 30 - May 4, 1995	Publication date for notice of 30-day extension of Draft EIR/S public review period in: • Lassen County Times • Reno Gazette Journal • Modoc County Record • The Sacramento Bee • The Mountain Messenger
June 2, 1995	End of 60-day public review period for Draft EIR/S
November 1995	Final EIR/S released* • Notice of Availability of Final EIR/S issued by the EPA and BLM, mailed out to project mailing list (1720 people), and published in the Federal Register • Notice of Determination for Final EIR/S issued by the CPUC

* Project documents were made available for public viewing, upon their release, at the following document repository sites:

Modoc County Library
212 W. 3rd St.
Alturas, CA 96101

Lassen County Library
225 S. Roop St.
Susanville, CA 96130

Loyalton City Hall
210 Front St.
Loyalton, CA 96118

Washoe County Library
4001 S. Virginia St.
Reno, NV 89502

CPUC
505 Van Ness Avenue
San Francisco, CA 94102

BLM - Susanville District
705 Hall Street
Susanville, CA 96130

BLM - Susanville District
Alturas Resource Area Office
708 W. 12th Street
Alturas, CA 96101-3102

BLM - Lahontan Resource Area
1535 Hot Springs Road, # 300
Carson City, NV 89706

Toiyabe National Forest
1200 Franklin Way
Sparks, NV 89431

Modoc National Forest
800 West 12th St
Alturas, CA 96101

Part D (Comparison of Alternatives): A discussion of the environmentally superior alternative and summary of the relative advantages and disadvantages of the Proposed Project and alternatives.

Part E (Additional Long-Term Implications): A discussion of short-term use versus long-term maintenance and enhancement of the environment, irreversible environmental changes, and growth-inducing impacts.

Part F (Proposed Mitigation Monitoring, Compliance and Reporting Plan): A tabulation of the Mitigation Monitoring Program for the Proposed Project, including a discussion of the organization of the Program, roles and responsibilities, and general monitoring procedures.

Base Maps: Illustrate the alignment of the Proposed Project and resources within the study corridor. Base maps were included as Appendix C in the Draft EIR/S.

VOLUME II - COMMENTS AND RESPONSES

Part G (Comments): Each comment received on the Draft EIR/S is categorized and presented.

Part H (Responses to Comments): A response to each comment received is provided.

VOLUME III - APPENDICES

APPENDIX A - Glossary, Preparers, Contacts

- Glossary/Abbreviations
- List of Preparers of this Document and Their Qualifications
- Persons and Organizations Consulted
- Distribution List for EIR/S

APPENDIX B - Scoping and Noticing

- Scoping Report
- List of Commenters
- LMUD Public Notice

APPENDIX C - Segment/Structure Coordinate Summary

APPENDIX D - Air Quality

APPENDIX E - Biological Resources

- Biological Assessment
- Bird Collision Report
- Community and Habitat Restoration Plan
- No Structure Zone Biological Resources

- Access Road Survey Summary
- East Secret Valley Biological Survey Report
- Plant Community Survey Report
- Waterfowl Survey Summary
- Winter Raptor Survey Summary
- Greater Sandhill Crane Survey Summary

APPENDIX F - Geology and Soils

APPENDIX G - Noise

APPENDIX H - Visual Contrast Rating Forms

APPENDIX I - Cultural Resources

- Access Road Survey Summary
- Historic Properties Treatment Plan Summary

A.3 CPUC REGULATORY PERSPECTIVE

The CPUC regulates the services and rates of privately-owned, intrastate utilities and transportation companies which offer services to the public, including the transmission of electricity. Much of the CPUC's regulation is carried out through judicial and legislative style processes under the direction of an Administrative Law Judge (ALJ) and, ultimately, the Commissioners. Like a court, the ALJ and Commissioners may take testimony, issue decisions and orders, cite for contempt, and subpoena witnesses or records. The Commissioners' decisions and orders may be appealed only to the California Supreme Court.

SPPCo's request for CPUC authority will move through the standard CPUC decision processes, as defined in the CPUC Rules of Practice and Procedure, the Public Utilities Code and CPUC General Orders (GOs). CPUC GO 131-C, since amended to GO 131-D, requires utilities to seek Commission authorization (in the form of a Certificate of Public Convenience and Necessity, or CPCN) for proposed transmission facilities greater than 200 kV. The purpose of the CPCN process is to enable the CPUC to make a determination regarding the need for the project and to evaluate the project's proposed design and engineering, compliance with all applicable laws, and impact on the environment.

Under the California Public Utilities Code, no electric utility may begin construction of any line, plant, or system addition, without first obtaining a CPCN from the CPUC stating that the present or future public necessity requires or will require such construction. The Applicant must demonstrate that the Proposed Project is technically feasible, cost-effective, complies with all applicable laws, ordinances, rules, and regulations, and that it will not interfere with the operation of any nearby or competing utility.

The assigned Administrative Law Judge conducted a Pre-Hearing Conference on February 6, 1995, to initiate the CPUC's formal CPCN process. The purpose of the Pre-Hearing Conference was to identify the interested parties, the positions of the parties, the scope of issues to be addressed, and other procedural matters. Following the Pre-Hearing Conference, the assigned Administrative Law Judge set the following schedule for the filing of prepared testimony and conducting evidentiary Hearings. The Applicant was directed to file its prepared testimony on March 30, 1995. All other interested parties were directed to file their prepared testimony by May 4, 1995. Responses to testimony were to be served by May 15, 1995. Evidentiary hearings were held from May 22, 1995 through May 25, 1995 and again on June 1, 1995.

For development projects which require discretionary approval from a state agency, CEQA requires agencies to prepare and certify an EIR that assesses the potential environmental impacts of the Proposed Project and alternatives. The CPUC, as Lead State Agency, shall be responsible for ensuring compliance with all requirements of CEQA. Since the Proposed Project also requires federal discretionary approval, the CPUC is preparing this EIR/S jointly with the BLM to ensure that both parties have the information required to understand the environmental consequences of the project, and take actions that protect, restore and enhance the environment. The preparation of this EIR/S has run parallel with the CPCN process described above.

The CPUC will use the results of the Final EIR/S as an element in the review of SPPCo's application for a CPCN. A CPCN is granted only if the CPUC finds that the evidence produced regarding technical feasibility, financing, rates, demand, cost-effectiveness, existing facilities and service, environmental impacts, and other issues demonstrates that a project is required by the public convenience and necessity. The Commission's discretionary decision on the Proposed Project will not be issued until the Commission has had opportunity to review and certify the Final EIR/S. If the Proposed Project is found to have any significant impacts that cannot be mitigated, then the CPUC may either deny the application or approve the project and adopt a statement of overriding considerations.

A.4 BLM REGULATORY PERSPECTIVE

The Proposed Project and routing alternatives identified for the proposed Alturas Transmission Line Project would cross federal lands managed by the BLM, USFS and Sierra Army Depot (SIAD). These agencies manage federal property falling under their respective jurisdictions in accordance with numerous Federal land management laws, including the Federal Land Policy and Management Act. In addition, the project would interconnect to the Bonneville Power Administration, (BPA), U.S. Department of Energy. This Federal agency transmits electric power to the Pacific Northwest in accordance with the Bonneville Project Act 1937. (See Section A.6.9.1) These agencies must comply with the requirements of NEPA, 42 USC 4321, et seq., and related requirements under 40 CFR 1500-1508.

As required by NEPA, an EIS will be included in every recommendation or report on proposals significantly affecting the quality of the human environment. The proposed Alturas Transmission Line Project falls under this NEPA category. In accordance with regulations under 40 CFR 1501.5, the BLM (Eagle Lake Resource Area) has been designated as the Lead Federal Agency for the preparation of this EIR/S, with the USFS, SIAD and BPA acting as cooperating agencies. The BLM, as Lead Federal

Agency, shall be responsible for ensuring compliance with all requirements of NEPA and Council on Environmental Quality regulations under 40 CFR 1500, as well as the procedures outlined in the Forest Service Handbook 1909.15, Environmental Policy and Procedures Handbook.

The Alturas Transmission Line Project will require approval of a right-of-way (ROW) grant, plan amendments, and special use permit before any construction could occur. The BLM will use the results of the EIR/S as an element in the review of SPPCo's application for a ROW grant across BLM lands. Although the BLM has lead responsibility for federal agencies in the preparation of this EIR/S, the BLM, USFS, SIAD and BPA will issue separate approvals for the Proposed Project, in the form of Records of Decision (ROD). These RODs must state what the decision was, identify all alternatives considered in reaching the decision, specify the alternative or alternatives considered to be environmentally superior, and state whether all practicable means to avoid or minimize environmental harm from the alternative selected have been adopted, and if not, why they were not. The BLM, USFS and SIAD will coordinate their respective RODs to ensure that the same preferred agency alternative is selected, with compatible mitigation measures. The RODs of the BLM, USFS and BPA are subject to a formal appeal process. In addition, the USFS Modoc National Forest could use this EIR/S in its decision process for a plan amendment to their Modoc National Forest Land and Resource Management Plan. Similarly, the USFS Toiyake National Forest could use this EIR/S for amending the Toiyabe National Forest Land and Resource Management Plan for lands recently acquired from Granite Corporation.

A.5 AGENCY USE OF THIS DOCUMENT

This EIR/S has been prepared to meet the needs of local, state, and federal permitting agencies in considering SPPCo's application for the Alturas Transmission Line Project. This document reflects comments and concerns made by agencies and the public during the scoping process and the Notice of Preparation/Notice of Intent comment periods (March through May, 1994), and oral and written comments received on the Draft EIR/S. Based on the comments received on the Draft, this Final EIR/S has been prepared to respond to, address, and incorporate, as appropriate, the comments received on the Draft. The EIR/S does not make recommendations regarding the approval or denial of the project; it is purely informational in content.

As discussed in Sections A.3 and A.4, the CPUC and BLM are the Lead State and Federal Agencies for compliance with CEQA and NEPA, respectively, with the USFS, SIAD and BPA acting as a federal cooperating agencies. The CPUC, BLM, USFS, SIAD, and BPA will be required to take initial, but separate actions on the EIR/S and the project; each agency will determine the adequacy of the Final EIR/S and, if adequate, will certify the document. Subsequent to certification of the Final EIR/S, the CPUC, BLM, USFS, SIAD, and BPA will issue separate decisions on the pending transmission line applications. The U.S. Army Corps of Engineers will also use this EIR/S for its permit decisions.

This EIR/S will also be utilized by State agencies (i.e., California Department of Fish and Game, California State Lands Commission, State [California and Nevada] Historic Preservation Offices, etc.) to evaluate the project for their permit decisions. State agencies with permitting authority over the project are referred to as responsible or trustee agencies. Given that a portion of the Proposed Project is located within the State of Nevada, an additional document will need to be prepared to satisfy the requirements of the Nevada Utility Environmental Protection Act (UEPA).

Because of the statewide interest in utility regulation, CPUC jurisdiction preempts any county discretionary permitting authority over the Proposed Project (Cal. Const., Art. XII, 8). Although local cities and counties do not have discretionary authority over the Proposed Project, the Lead Agencies consider local city and county planning policies in their review of the project. Furthermore, the CPUC encourages utilities to cooperate with local jurisdictions to the extent practicable. The counties and cities will maintain ministerial permit authority over non-electrical components of the Proposed Project.

As specified in the Mitigation Monitoring Program in Part F of this EIR/S, the noted Federal, State, and local agencies will have their respective roles in reviewing and approving specific mitigation documents or agreements for the Proposed Project.

Table A-2 presents a summary of potential federal, state and local permits and authorizations required for the Proposed Project.

A.6 PURPOSE AND NEED FOR THE PROJECT

Section A.6, Purpose and Need for the Project, provides an overview of the necessity for the Proposed Project as stated by the Applicant. As described in Section A.3, the CPUC CPCN process was conducted in parallel to the preparation of this EIR/S. The regional, electrical transmission network and SPPCo system are provided as background information. This section provides a synopsis of information reviewed relating to the Proposed Project and Alternatives. The purpose of this review was to independently verify all facts and assertions regarding the purpose and need of the Proposed Project, as presented by the Applicant, SPPCo. Section A.7, References, contains a list of all studies, memoranda, etc., reviewed as well as persons contacted.

To help explain the terms and acronyms of the electric utility industry used in this document, a glossary of technical terms is provided in Subsection A.6.10. A general glossary is provided in Appendix A.

A.6.1 REGIONAL TRANSMISSION NETWORK OVERVIEW

A.6.1.1 Electric Power Network Overview

The electrical network that interconnects utilities in the western United States, Canada, and Mexico is said to be the largest machine ever constructed. Essentially all utilities in this network are connected either directly or indirectly. This network provides a means for these utilities to buy, sell, or exchange power or electrical services that improve the reliability of service to their respective customers.

Table A-2 Summary of Potential Federal, State, and Local Permits and Authorizations

Concern	Action Requiring Permit Approval or Review	Agency	Permit Required or Approval	Statutory Authority
FEDERAL				
NEPA Compliance	Encroachment upon BLM lands	U.S. Bureau of Land Management	Approval of right-of-way Grant, Plan Amendments	NEPA, 42 USC 4321 et. seq.; FLPMA, 43 USC 1701 et. seq.
NEPA Compliance Biological Resources Designation of Right-of-Way Corridor	Encroachment upon Forest Service lands	U.S. Department. of Agriculture, Forest Service, Toiyabe & Modoc National Forest	Special Use Permit, Easement, or Land Exchange, Forest Land and Resource Management Plan Amendment	NEPA, Council of Environmental Quality Regulation - Forest Service Handbook 1909.15
Land Use	Encroachment upon Sierra Army Depot lands	U.S. Army Corps of Engineers	Approval of Easement of right-of-way	
Biological Resources - Wetlands	Encroachment upon wetlands	U.S. Army Corps of Engineers	Endangered Species Act Compliance Section 404 Permits	Endangered Species Act, Executive Order 11990 (Protection. of Wetlands)
Safety	Encroachment upon public air fields	Federal Aviation Administration	Obstruction Notice Part 77	
Utility Operations	Intertie to BPA System	Bonneville Power Administration (BPA), U.S. Dept. of Energy	Record of Decision	Bonneville Project Act of 1937 NEPA
STATE OF CALIFORNIA				
Public convenience and necessity CEQA Compliance	Project Construction	Public Utilities Commission	Certificate of Public Convenience and Necessity	CPUC Rules of Practice & Procedure, Public Utilities Code, CPUC Gen. Orders; CEQA (Public Resource Code Sections 21000 et. seq.)
Biological Resources	Alteration of the natural state of any stream	Department of Fish & Game	Stream Alteration Agreement (1601 and 1603)	California Fish and Game Code Sections 1600-1607
Biological Resources	Removal of merchantable timber	Department of Forestry	Timber Harvest Permit, Timber Alternation Permit	
Cultural Resources	Project Construction	State Historic Preservation Office	National Historic Preservation Act Compliance	National Historic Preservation Act, Section 106
Water Quality	Project Construction	Regional Water Quality Control Board	Discharge Permit or Waiver	Porter Cologne Calif. Water Code Section 13000 et. seq.
Land Use	Encroachment upon navigable water ways of school lands	State Lands Commission	Lease or Permit	Public Resource Code Section 6301
Transportation	Encroachment within, under, or over state highway right-of-way	Department of Transportation	Encroachment or Crossing Permit, Native American Heritage Community Notice	California Streets & Highways Code, Sections 660-734

Concern	Action Requiring Permit Approval or Review	Agency	Permit Required or Approval	Statutory Authority
STATE OF NEVADA				
Nevada UEPA Compliance	Project Construction	Public Service Commission	Nevada UEPA Permit	Nevada UEPA
Biological Resources	Alternation of natural state of any stream	Division of Wildlife	Stream Alteration Permit	
Water Quality	Project Construction	Division of Environmental Protection	NPDES Surface Area Disturbance Permit	
Cultural Resources	Project Construction	State Historic Preservation Office	National Historic Preservation Act Compliance	National Historic Preservation Act, Sect. 106
Transportation	Encroachment within, under, or over state highway right-of-way	Department of Transportation	Encroachment or Crossing Permit	
CALIFORNIA MUNICIPALITIES				
Land Use	Project construction of non-electrical components	Alturas/Modoc County Planning Departments	Building/Grading Permits	Alturas/Modoc County General Plan & Zoning Ordinance
Land Use	Project construction of non-electrical components	Lassen County Planning Department	County Road Encroachment Permit, Building/Grading Permits	Lassen County General Plan & Zoning Ordinance
Land Use	Project Construction of non-electrical components	Sierra County Planning Department	Building/Grading Permits	Sierra County Plan & Zoning Ordinance
Air Quality	Project Construction	Modoc County APCD Lassen County APCD Northern Sierra County APCD	Consistency with Fugitive Dust, Emission Rules	Federal Clear Air Act California Clean Air Act
NEVADA MUNICIPALITIES				
Land Use	Project construction of non-electrical components	Washoe County Dept. of Development Review	Grading Permits, Regional Plan Conformance	Regional Plan
Land Use	Project construction of non-electrical components	City of Reno Community Development Department	Special Use Permit	General Plan & Zoning Ordinance
Air Quality	Project Construction	Washoe County Bureau of Air Quality, Washoe County of Air Pollution Control Agency, Truckee Meadows Air Basin	Consistency with Fugitive Dust, Emission Rules	Federal Clean Air Act California Clean Air Act

The network is divided into control areas which may consist of one or more utilities with one utility designated the primary operator of each area. The control area operator typically owns most or all of the transmission facilities in the area. There may be other utilities embedded inside the control area that rely on the control area operator for transmission service to transmit power from an outside source. A large utility may have responsibilities to transmit power to its own retail customers and to smaller utilities or wholesale customers (transmission service customers). The transmission of power over a utility's transmission system for another entity is called "wheeling." Sections A.6.1.2 and A.6.1.3 discuss the control area in which SPPCo operates.

The simple, traditional utility system consisted of power generation within the utility service area (native generation), transmission lines to bring the generated power to major customer clusters (or load centers) and distribution lines to distribute the power to customers. As utilities became large and began interconnecting with one another, sources of power from other areas became cheaper alternatives to native generation and utilities began transporting purchased power into their service areas on the transmission network (this activity is known as power importing). Later, wanting to take advantage of the marketplace, smaller utilities began to seek access to the major transmission ties as a source of power. More recently, new laws have allowed independent power producers to sell their power to other utilities through the transmission network.

Network interconnections offer benefits beyond the sale and purchase of power between utilities. These interconnections also allow utilities to share responsibilities to provide reliable service to their respective customers. For example, if a particular utility's supply facilities fail, an interconnection agreement with another utility could provide for an emergency backup power source to serve customers while the system is being restored.

Interconnections also allow utilities to take advantage of diversity in regional customer demands. The best example of this diversity benefit is that which occurs between the regions of Pacific Northwest and the Pacific Southwest. The Pacific Northwest has a preponderance of hydroelectric generation which peaks in output with water run-off from the snow melt during the spring and summer. The Pacific Southwest customer demands are highest during much of this period with air conditioning loads, providing a natural need for this abundance of power. During the winter when the Northwest demand peaks due to heating requirements, hydroelectric power output is down. However, Southwest winter demand is low, so much of the southwest coal, gas and nuclear generation is available for export to the Northwest. The 500 kV Pacific AC Intertie and the 1000 kV Pacific DC Intertie were built in the 1960's to transmit power back and forth during these periods and take advantage of this diversity. Other projects later followed to increase this capability.

The interdependence of utilities was further solidified in 1992 when Congress passed the Energy Policy Act of 1992, requiring utilities who own transmission facilities to provide access to those utilities who do not have transmission facilities. This access allows utilities without transmission facilities to connect to needed resources outside their respective areas. However, transmission-owning utilities are not responsible for constructing new transmission facilities required to respond to requests for transmission service.

A.6.1.2 Western Systems Coordinating Council

The Western Systems Coordinating Council (WSCC) is a voluntary alliance of over 80 electric utilities and affiliates in fourteen western states, and portions of Canada and Mexico. These member utilities provide electrical service to approximately 59 million people. WSCC is one of nine reliability councils formed in the United States to address national concerns regarding the reliability of the interconnected bulk power system and the ability to operate these systems without widespread failures in electric service. Among its members are the Proposed Project proponent, SPPCo, and the utility to which the Proposed Project would interconnect, the Bonneville Power Administration (BPA). Figure A.6-1 illustrates the WSCC service area and major transmission facilities within it.

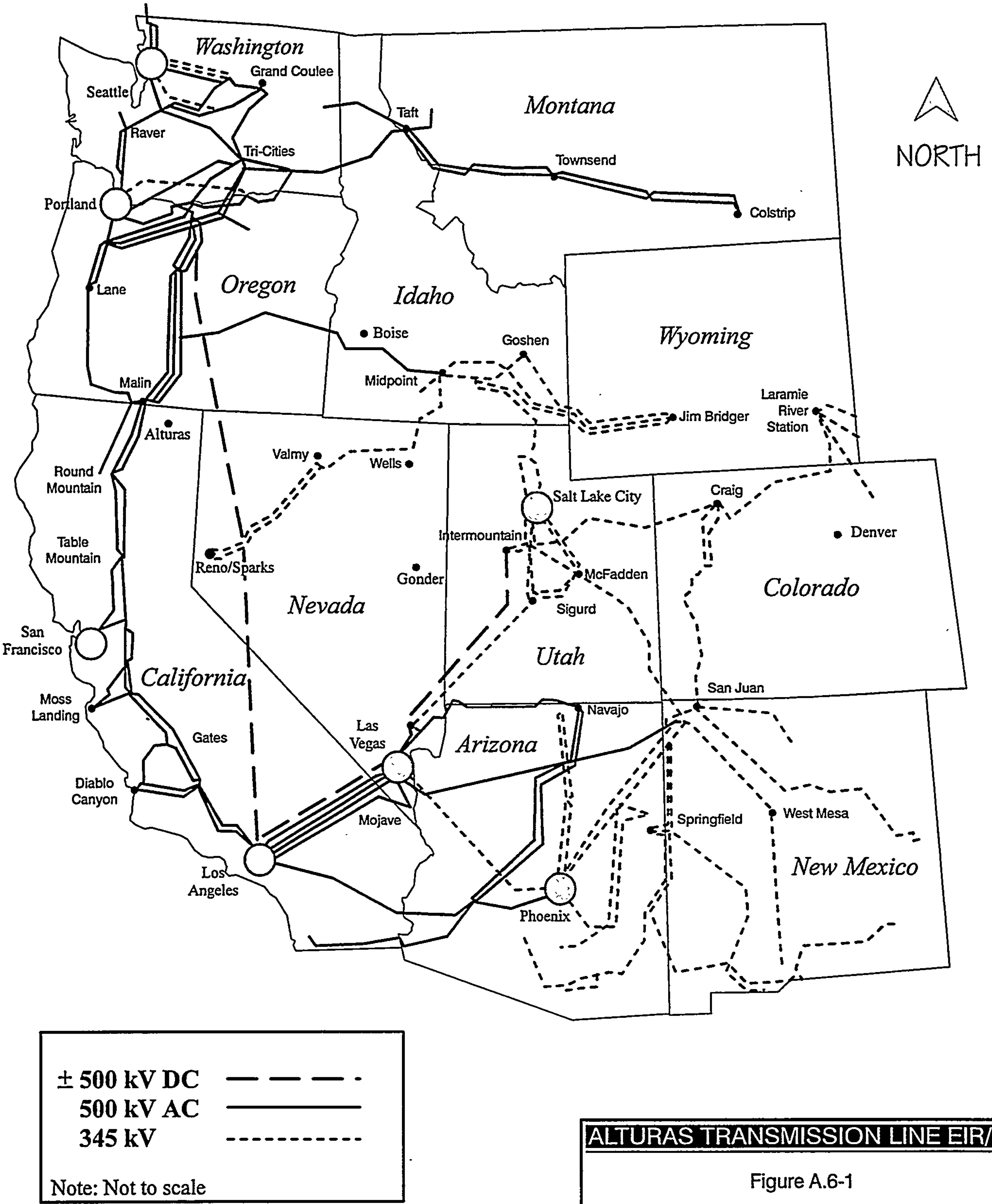
The WSCC is divided into four major areas: (1) the Northwest Power Pool Area, (2) the Rocky Mountain Power Area, (3) the Arizona-New Mexico Power Area and (4) the California-Southern Nevada Power Area. These four areas are interconnected with extra high voltage transmission facilities to interconnect the diverse set of resources and customer demand characteristics unique to each area. The WSCC provides a means for its members to coordinate plans with one another to enhance system reliability and efficiency for all.

WSCC is organized into committees and groups which set guidelines for its members to follow. Planning, design and operational reliability criteria are established and regularly updated. Procedures for regional planning and project review are established for study groups to evaluate and determine capabilities of (or "rate") future projects and determine their potential effects on other members.

Anytime a WSCC member proposes an interconnection with another control area, there is the possibility of significant impacts on other members. WSCC has established programs and procedures which allow members to evaluate new projects and their impacts on others, and how the proposed interconnection should be operated. WSCC has established a special study group for such an evaluation of the Proposed Project. SPPCo, Idaho Power Company (IPC), BPA, Pacific Gas and Electric Company (PG&E), Washington Water and Power (WWP), Pacific Power and Light and Utah Power and Light (PacifiCorp), Deseret Generation & Transmission, the Sacramento Municipal Utility District, Nevada Power Company and Portland General Electric Company are WSCC members who are participating in this study.

The WSCC study is divided into two preconstruction phases. The first phase of the study addressed the import capacity improvement potential of the Proposed Project and was completed in December 1993. Potential impacts on other utilities were identified and recommended for further study.

The second phase of the study addressed the impact of the Proposed Project on the operation of WSCC member utilities. The study was performed by SPPCo with participation of the utilities in the WSCC Group. Its results show conformance to WSCC criterion with no adverse impacts to other utilities. The Phase II study was completed in February 1995. The study concluded that the Proposed Project will have 300 MW of bi-directional transfer capability. SPPCo has determined that this will increase the total SPPCo import capability from 360 MW to about 660 MW.



ALTURAS TRANSMISSION LINE EIR/S

Figure A.6-1

Western Systems Coordinating Council Regional Transmission Network

Source: Western Systems Coordinating Council

A.6.1.3 Northwest Power Pool

The Northwest Power Pool (NPP) is one of the four subgroups of the WSCC. It consists of twenty utilities located in the northwest United States and western Canada (including SPPCo and BPA). The pool has established an operating manual which sets forth a program for coordinated operations in this area, where power generation is predominantly hydroelectric.

A.6.1.4 Legislative Framework

In September 1988, the State of California passed what is known as the Garamendi Bill (Senate Bill No. 2431). This bill declared, among all other things, that where there is a need to construct additional transmission capacity, agreement among all interested utilities on the efficient use of that capacity will be pursued and priorities for planning and developing new transmission facilities were set forth. Section C.8 of this EIR/S includes an analysis of the consistency of the Proposed Project with Senate Bill 2431.

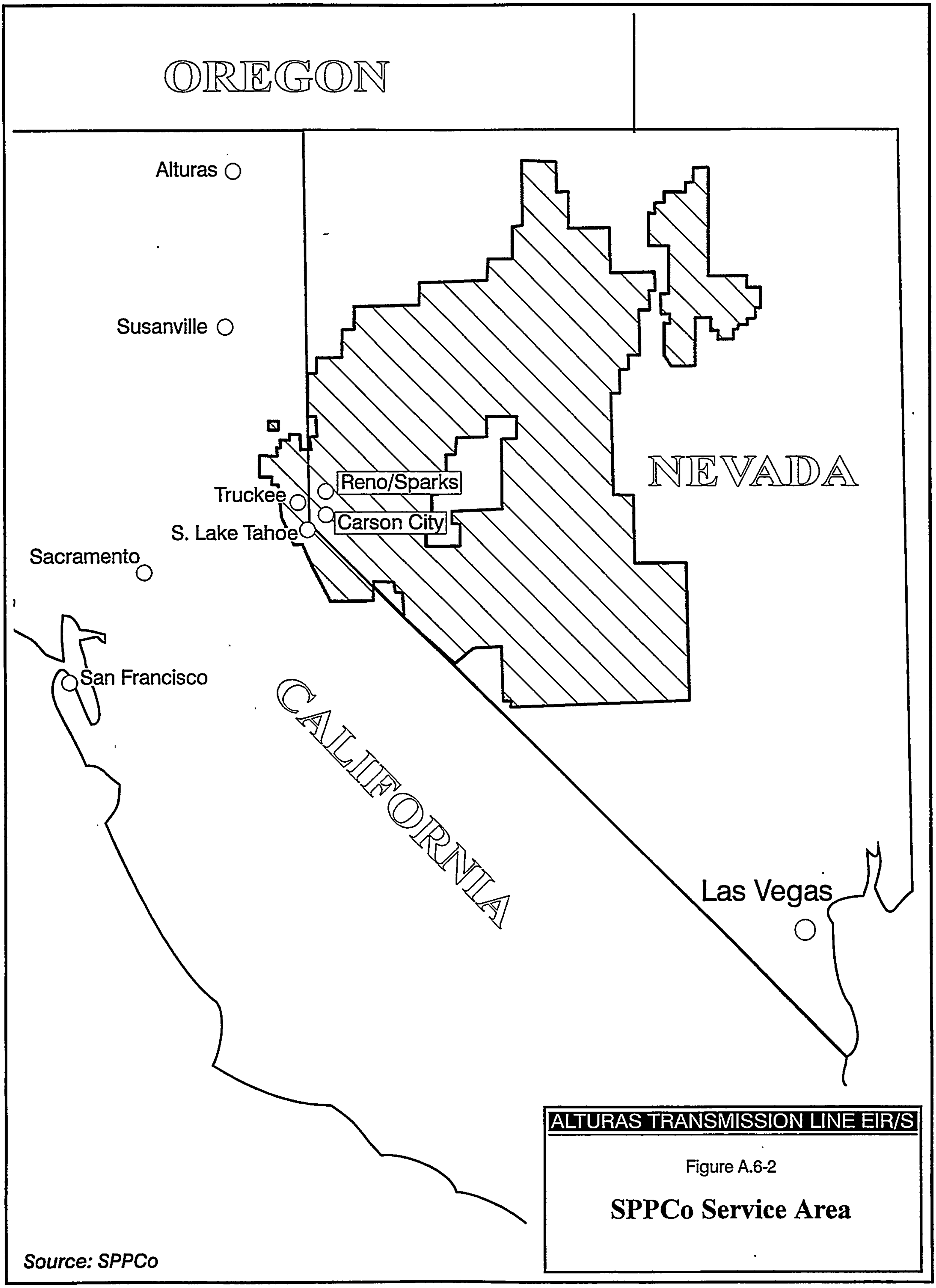
A.6.2 SIERRA PACIFIC POWER COMPANY (SPPCo) SYSTEM OVERVIEW

SPPCo is an investor-owned electric, gas, and water utility based in Reno, Nevada. As an electric utility it is engaged in the generation, purchase, transmission, distribution and sale of electric energy. SPPCo serves over 250,000 retail customers in northern Nevada and Northeastern California with a service territory of over 50,000 square miles. Approximately 84 percent of SPPCo's customer base is in Nevada, with the remaining 16 percent or approximately 40,000 customers located in California. Figure A.6-2 illustrates the SPPCo service area. In addition, SPPCo provides transmission service or "wheels" to loads embedded within SPPCo's control area. These transmission customers include BPA (for delivering power to the Wells Rural Electric Company [Wells] and Harney Electric Cooperative, Inc. [Harney]), and to Mt. Wheeler Power (for delivering power to Ely and Eureka, Nevada).

To fully understand the operation of the SPPCo system it is important to have a basic understanding of its geography. SPPCo is divided into five districts: Reno, Eastern, Tahoe, Carson and South Eastern. Its major customer concentration is in the Reno District, which consists of a mix of residential, gambling/casino, hotel, commercial and industrial customers. Mining is a major energy user in the Eastern District. Recreational energy use dominates the Tahoe District, and the Carson and South Eastern Districts are primarily rural areas with a lesser influence on the make-up of SPPCo's customer base. Figure A.6-3 is an illustration of the SPPCo area customer winter peak demands (loads) for the 1992/93/94 time frame. As illustrated by Figure A.6-3, approximately 72 percent of SPPCo's load is in the Reno/Carson/Tahoe area.

Figure A.6-4 illustrates the interconnection of the SPPCo system to the WSCC system through the following transmission lines:

- The 230 kV line from Gonder to PacifiCorp (merger of Pacific Power and Light, and Utah Power and Light)
- The 230 kV line from Gonder to Intermountain Power Project (IPP)
- The two 55 kV lines to Southern California Edison Company (SCE)
- The two 120 kV lines and one 60 kV to PG&E
- The 345 kV line from Humboldt to IPC.

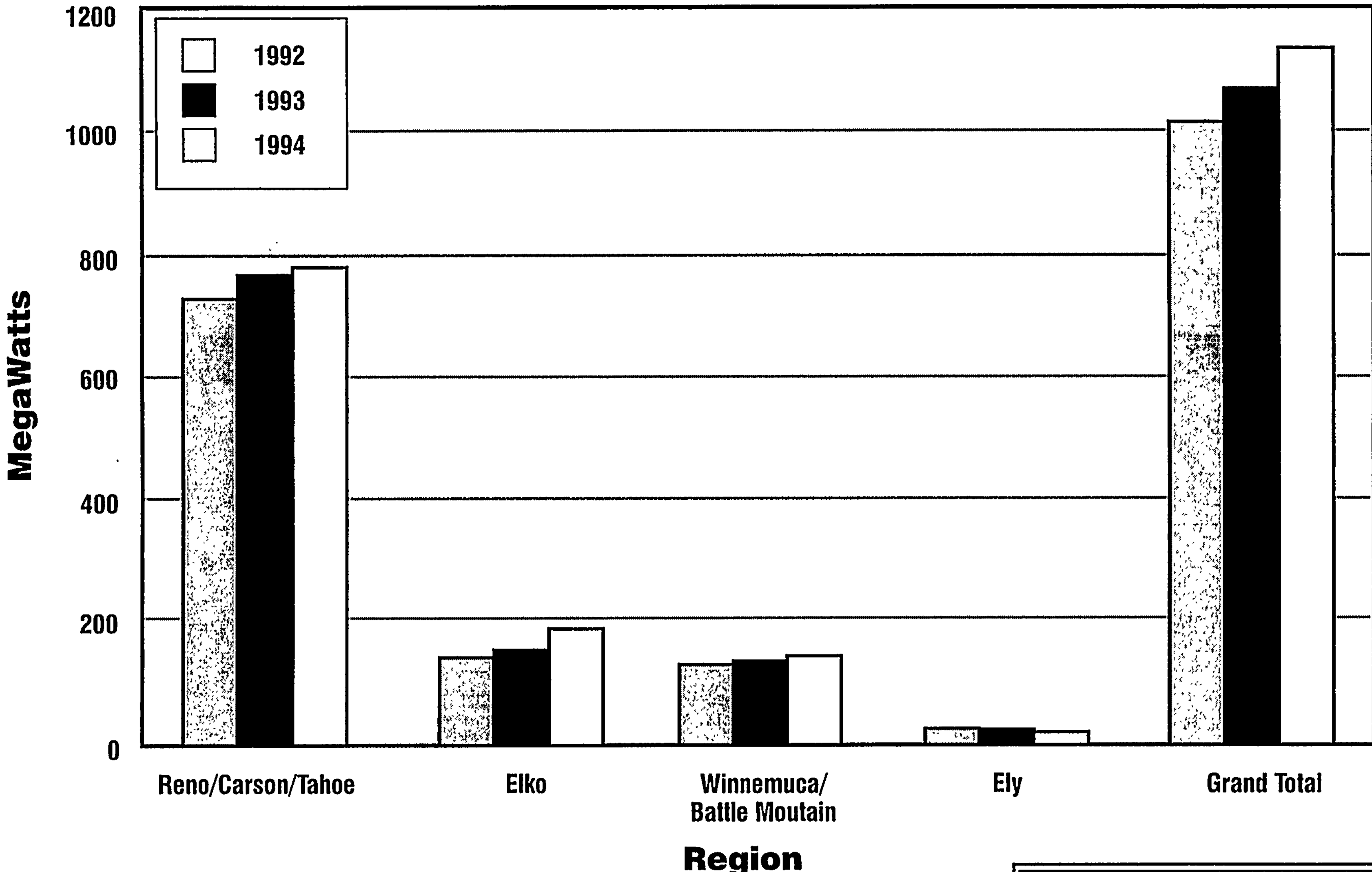


ALTURAS TRANSMISSION LINE EIR/S

Figure A.6-2

SPPCo Service Area

Source: SPPCo

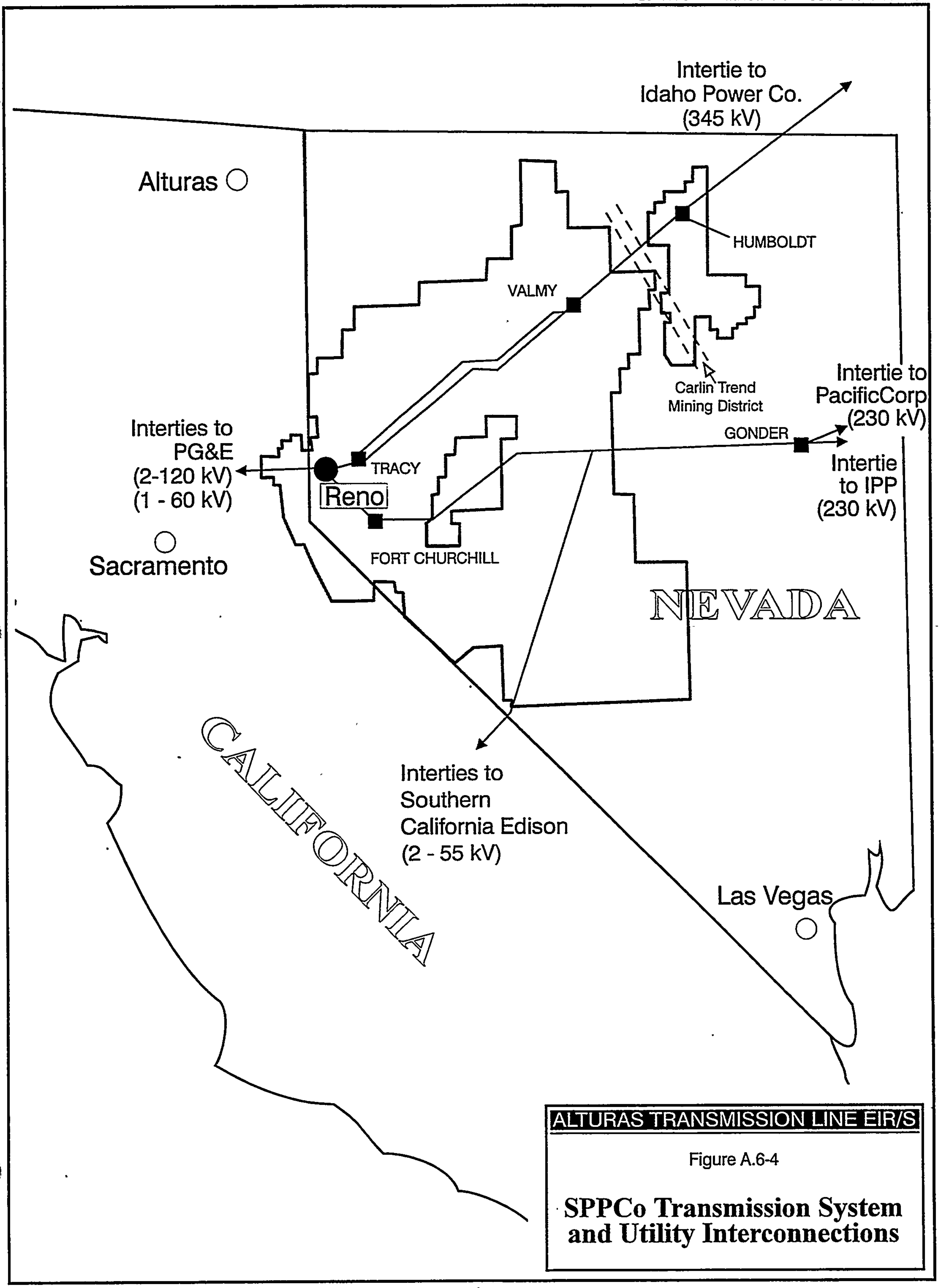


Source: SPPCo

ALTURAS TRANSMISSION LINE EIR/S

Figure A.6-3

1992-1994 Winter Peak Loads



ALTURAS TRANSMISSION LINE EIR/S

Figure A.6-4

SPPCo Transmission System and Utility Interconnections

The most significant interconnection is the 345 kV line from Humboldt to the northeast with IPC. Major electrical generation supplies come internally from Valmy, Tracy and Fort Churchill and externally on the IPC interconnection.

The subsections below describe SPPCo's system, leading up to the installation of the Proposed Project scheduled for a 1997 on-line date.

A.6.2.1 SPPCo System Demand/Load

SPPCo sold approximately 6500 gigawatt-hours (gWhs) in 1993 and sold over 6700 gWh in 1994. The 1993 system peak demand was 1074 megawatts (MW) and in 1994 it increased to 1130 MW. As discussed in Section A.6.2 and illustrated on Figure A.6-3, about 72% of SPPCo's system load is in the Reno/Carson/Tahoe area. In its 1993 Electric Resource Plan (ERP), submitted to the Public Service Commission of Nevada (PSCN), SPPCo forecasted an average demand growth rate of 4.31 percent and an average sales growth rate of 4.81 percent for the years 1993 to 1997. The 1995 - 2014 Electric and Gas Integrated Resource Plan (1995 IRP) forecast for demand growth decreased slightly and SPPCo is now expected to supply 1319 MW of capacity in the summer of 1997. Table A-3 presents SPPCo's projected growth in demand through the year 1997 according to the 1995 IRP. These forecasted amounts of capacity and energy include expected sales to SPPCo wholesale customers.

Table A-3 SPPCo Actual and Forecasted Demand and Sales

Year		1993[1]	1994[1]	1995[2]	1996[2]	1997[2]
Summer Peak Demand	MW	1074	1130	1183	1242	1319
	Growth (%)	1.0%	5.2%	4.7%	5.0%	6.2%
Winter Peak Demand	MW	1065	1099	1216	1271	1331
	Growth (%)	0.8%	3.2%	10.6%	4.5%	4.7%
Energy Sales	(gWhs)	6478	6763	7258	7755	8186
	Growth (%)	4.7%	4.4%	7.3%	6.8%	5.6%

[1] Actual

[2] Forecast based on 1995 IRP. (Approved by NPSC, September 1995)

SPPCo loads peak at approximately the same level in the winter and summer during extreme temperatures. For instance, in 1993, SPPCo peaked at 1074 MW in the summer and 1065 MW in the winter.

Residential loads accounted for approximately 26 percent of SPPCo sales in 1994 Mining also accounted for about 26 percent of SPPCo total sales. Casino, gambling and hotels accounted for approximately 11 percent of sales. According to the 1995 IRP, residential sales are expected to grow at a rate of 2.6 percent per year, while casino related loads are expected to grow at 2.2 percent in the near term 1995-1999. The 1995 IRP forecasted mining to grow at a 10.7 percent annual rate from 1994 to 1999 which makes it the largest sector in SPPCo's customers.

Mining is also the fastest growing sector of SPPCo customers. In 1992, mining only accounted for about 11 percent of total sales, but by 1997 it is expected to grow to about 32 percent of sales. Various current proposals for a tax on mining operations on federal lands could, if passed, dampen this growth. The proposed tax has decreased from an assessment of 12.5 percent on gross revenues to 3.5 percent on net revenues (the budget proposal is still in the House Resource Committee). In addition, the price of gold has risen from $330 to approximately $375 per ounce, mitigating the potential loss to profits. Finally, a major mining facility served by SPPCo on federal lands has been granted a land patent under current law which allows expansion through the year 2000. Another major mining facility has also filed a similar injunction to gain their pending land patents under existing law. These grants should solidify these mining businesses' plans to continue their operational expansions.

Because of a series of dry years, irrigation energy loads have also experienced rapid growth. However, irrigation accounts for a relatively small percentage of total sales and is expected to return to average levels as typical weather conditions return. Other sectors of SPPCo's customer sales have grown and are expected to continue growing at relatively constant rates.

Geographically, growth is expected to be most prevalent in the Eastern District where mining in the Carlin Trend area is predominant (see Figure A.6-4). Residential loads, especially in the Sparks, Spanish Springs, and Stead areas are also experiencing higher than average growth.

A.6.2.2 SPPCo's Supply System

SPPCo supplies its electrical customers with power from three sources: internal self-owned generation, non-utility owned generation purchases (generated within SPPCo's service area), and external system purchases (imports) through the five transmission interconnections. The summer peak is the critical period for SPPCo to meet its customer demands as opposed to the winter peak, because many of SPPCo's power plants are derated during high ambient temperatures, resulting in a decrease in allowed power generation levels. According to the 1995 IRP, SPPCo customers demands during the summer of 1995 were met with the resources as summarized in Table A-4.

To meet the expected total growth in customer demands through the summer of 1997, SPPCo has added two combustion turbines at Tracy (Clark Mountain No. 3 and 4), providing an additional 138 MW of native generation for the summer peak. The Piñon Pine Power Plant Project (planned for operation in the spring of 1997) will add another 89 MW of summer-rated capacity. Short-term firm purchases from outside the SPPCo area are expected to provide the remaining capacity requirement to meet SPPCo's demand. These purchases would be made possible by the additional transmission capability of the Proposed Project.

SPPCo has submitted and received approval of its 1995 IRP. This plan assumes that the merger with WPP will not occur. As part of the IRP approval, the PSCN approved SPPCo's request to not seek approval to fill SPPCo's identified electric need in 1998 of 138 MW of summer rated capacity (two combustion turbines at Fort Churchill power plant). Figure A.6.5 illustrates SPPCo supply plans through

Table A-4 SPPCo Supply System Summer 1995

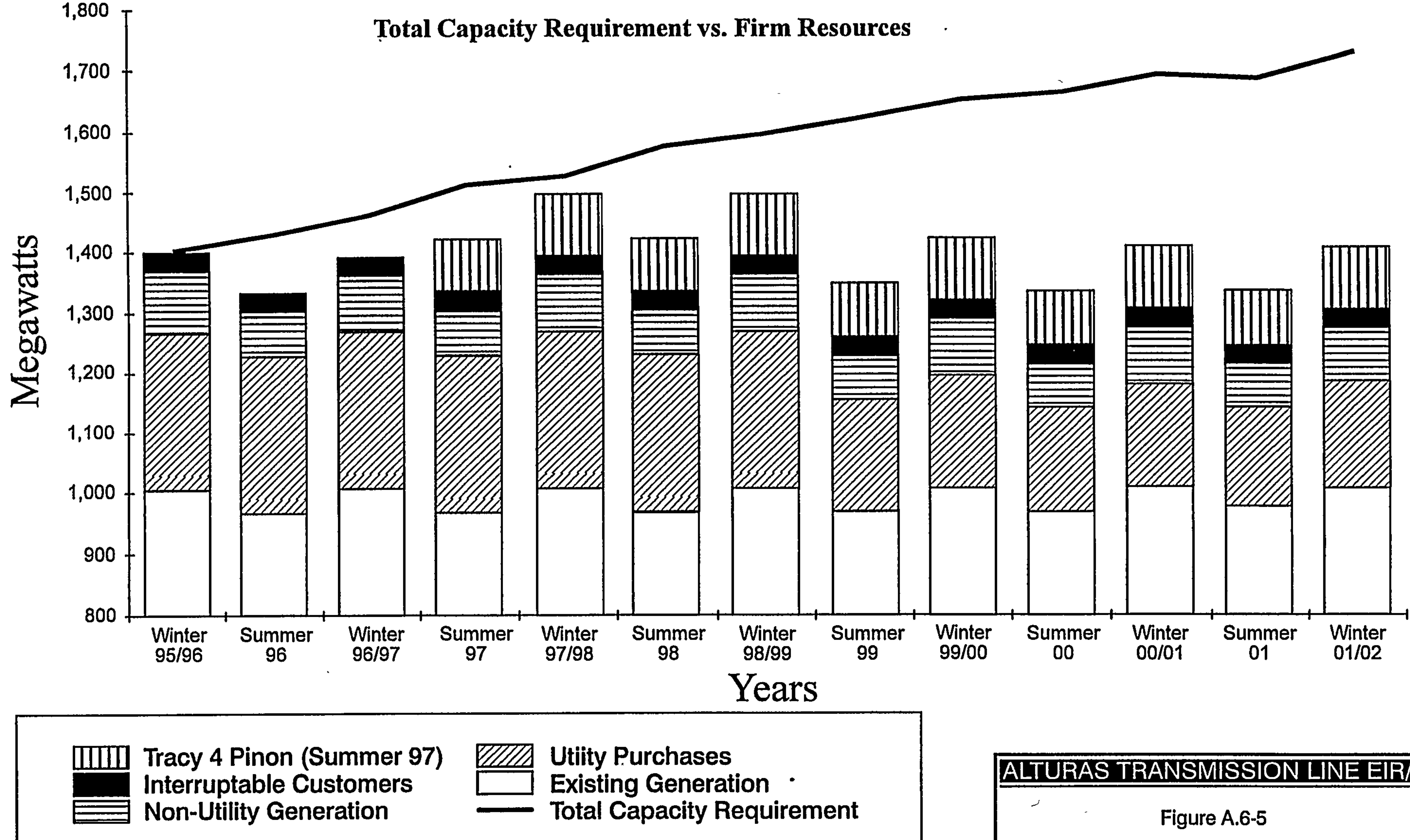
Power Source		Megawatts (MW) Supplied
Internal SPPCo-owned generation	Steam turbine generation (MW) - Tracy Units 1-3 (244 MW) - Fort Churchill (226 MW) - Valmy Units 1-2 (SPPCo share) (265 MW)	735
	Combustion turbine generation - Tracy Units (20 MW) - Winnemucca (14 MW) - Clark Mountain (Tracy) (138 MW)	172
	Diesel generation (26 units, various locations)	46
	Hydroelectric generation (6 units, various locations)	11
Non-utility generation		81
External system purchases		262
	TOTAL	1307

the winter of 2001-2002 according to the IRP's stipulations. With the additional import capacity provided by the Proposed Project, SPPCo plans to utilize short-term firm purchases to defer the construction of the Fort Churchill combustion turbines and "Greenfield" Power Plant; however, permitting and siting activities would continue. SPPCo will file an amendment to the 1995 IRP once the merger decision is approved. With the merger, SPPCo could possibly defer new generation planned for 1998 and beyond, by integrating resources with WPP.

SPPCo's interconnections have varying capabilities to import and export power depending on certain system conditions. SPPCo's total ability to import or export is limited to a simultaneous rating which depends on conditions in neighboring systems in accordance with WSCC operating criteria. The current simultaneous import capability for the SPPCo system is limited to 360 MW and the current simultaneous export capability is zero.

A.6.2.3 Wheeling Loads

SPPCo also supplies transmission wheeling services to wholesale customers. These customers are utilities which are imbedded in the SPPCo system in northern Nevada and eastern California. Power is supplied to these customers from others who are outside the SPPCo service area. These utilities contract with SPPCo for the use of its transmission system to transmit or "wheel" power over the SPPCo transmission lines. Table A-5 lists these wholesale customers, along with their respective past contracted use of the SPPCo system and their requested use for summer and winter through 1997.



Note 1: Capacity Requirements Includes Planning Reserve
Note 2: Existing Resources Reduce by 75 MW in 1999 plus 15 MW in 2000

Source: SPPCo, IRP, 1995, (considering PSCN approval of SPPCo's decision to not fill its identified electric need in 1998 of 138 MW).

ALTURAS TRANSMISSION LINE EIR/S

Figure A.6-5

Projected SPPCo System Loads vs. Existing Supplies

Table A-5 SPPCo Wheeling Demands

Summer Peak Wheeling Demand (MW)	1993[1]	1994[1]	1995[2]	1996[2]	1997[2]
Mt. Wheeler	27.1	27.7	38	100	100
Harney Electric	28.6	30.4	30	35	35
Wells Rural Electric[3]	37.8	34.4	69	72	75
Truckee Donner Public Utility District	0	0	7	7	19
Total	93.5	92.5	144	214	229
Growth (%)	5.7%	(1.1%)	55.7%	55.6%	6.7%
Winter Peak Wheeling Demand (MW)					
Mt. Wheeler	24.5	21.1	64	82	82
Harney Electric	0	10.1	10	25	25
Wells Rural Electric[3]	40.5	60.2	73	76	77
Truckee Donner Public Utility District	0	0	7	28	29
Total	65.0	91.4	154	211	213
Growth (%)	3.7%	40.6%	68.4%	37.0%	.9%

1 Actual
2 Forecast based on 1995 IRP
3 Wells Rural Electric loads are forecasted to exceed their 65 MW wheeling agreement with Sierra. The additional load will be serviced by Sierra generation until the Alturas Project is constructed.

A.6.2.4 SPPCo System Limitations

SPPCo's existing transmission system limits its capability to serve existing and forecasted customer loads in accordance with the criteria which SPPCo has established for itself based on WSCC criteria. These limitations result from a lack of transmission capability and affect SPPCo's wholesale and retail customer groups. For native load (retail) customers, these limitations result in reduced reliability and more expensive electricity since SPPCo has limited access to more economic power supplies. Transmission service (wholesale) customers experience a lack of import capability and reduced reliability from these limitations, in turn affecting their respective customers. More detailed discussions of how these limitations relate to the purpose and need of the Proposed Project are provided in the following sections. These limitations manifest themselves in four ways:

- Currently about two-thirds of SPPCo's power supply funnels through Tracy Substation which is located approximately 15 miles east of Reno. The power flows through Tracy predominately from east to west supplying primarily the Reno, Lake Tahoe, Sparks and northern valley areas. For a utility of SPPCo's size this represents a very high reliance on one system source for power supply. A major system disturbance at or east of the Tracy Substation could cause extensive and possible long-term service disruptions for those customers west of Tracy. As the loads grow in these areas, this exposure will be exacerbated without the development of additional system sources separate from Tracy.

- By 1997, growth in the Reno/Lake Tahoe area is expected to require reinforced transmission facilities from the generation and import sources in the eastern part of the SPPCo area. Additional transmission facilities will also be needed to accommodate anticipated growth in the North Valley area north of Reno.

- The growth in the SPPCo service area is requiring the addition of new resources. Because of existing import restrictions, modifications to the current system to satisfy growth are limited to the addition of native generation. New import capacity is expected to open access to less expensive power resources outside the

SPPCo area. This access to additional markets is expected to reduce power cost to native customers (see Figure A.6-5).

- Due to a lack of transmission capability, today's operational procedures would require SPPCo to automatically cut off service to a wholesale service customer (Wells), if the 345 kV intertie to Idaho fails. Additional service requested by Mt. Wheeler Power will have the same restrictions. Firm power requests by Truckee Donner Public Utility District (TDPUD) and Harney cannot be accommodated with existing facilities.

SPPCo addresses its system limitations through a state regulatory process. SPPCo is required by the State of Nevada to file an ERP with the PSCN every three years. This plan includes a 19 year forecast of SPPCo's customer electric power demand and energy consumption. The ERP integrates conservation and load management measures, and presents an approach to obtain supplies of electricity through new facilities to meet these customer needs. After subjecting the ERP to a public process of review, discovery, and hearings, the PSCN issues an "Opinion and Order" either accepting the plan or specifying the portions of the plan it deems inadequate. The Opinion and Order provides the mandate for action until it is either revised in an amendment or replaced by the next ERP three years later. SPPCo has addressed the limitations discussed in this section in its 1993 ERP, dated April 1, 1993; the PSCN has approved this plan. In 1995, SPPCo combined its ERP with its gas forecast and with PSCN approval, filed the 1995 IRP. The PSCN approved the 1995 IRP in September, 1995.

A.6.3 PROPOSED PROJECT OBJECTIVES AND DESIGN

Transmission facilities are typically constructed to satisfy one or more of three primary goals: (1) to transmit generation to the transmission grid or customer load centers, (2) to improve the reliability of delivering power to a certain area or customer group, and/or (3) to interconnect two different systems or control areas to take advantage of inter-utility operations and exchanges.

For each stated goal, an analogy can be drawn to road construction . In fact, transmission maps resemble road maps (see Figure A.6-1 which shows the transmission lines in the WSCC system):

- An example of the first of these goals would be a transmission line built to integrate a new suburban development with the existing utility system, or connecting a new remote generation plant to the system. An analogy might be building a new road to a new suburban area, manufacturing plant or industrial center.

- The second goal involves "beefing up" the existing system to accommodate changes throughout the system, resulting in creation of a weakness or "bottleneck" in serving power to customers. This would be similar to making an existing highway into a freeway or widening a bridge to eliminate traffic congestion.

- An example of the third goal would be a transmission line built over a significant distance so that two utility or utility groups could be connected to one another. Construction of a new freeway across the desert to connect two population centers provides a comparison to this objective.

The Proposed Project's objectives, which are discussed in more detail below, fall into both the second and third categories of the above goals.

Transmission facilities can be needed to improve system performance or reliability of service, or interconnect generation to load. These justifications are not achieved with cost/benefit analysis, but rather with technical studies showing need and least cost analysis. The Proposed Project's purpose and need has been justified based primarily on improving system reliability and performance. However, it also has the potential for realizing positive economic benefits.

A.6.3.1 Primary Objectives

In its PEA, SPPCo specified several objectives and benefits of the Proposed Project. For the purpose of this analysis, the Applicant-specified objectives have been grouped as either primary objectives, or as secondary objectives and benefits. The primary objectives of the Proposed Project are those considered critically necessary for SPPCo to operate as a viable utility within prudent utility practices. The secondary objectives and benefits of the Proposed Project are not considered principal to the Proposed Project justification, nor do they satisfy critical needs.

The three primary objectives of the Proposed Project are:

- **Increased SPPCo Import Capacity.** The Proposed Project would provide a direct interconnection to BPA in the Pacific Northwest; SPPCo is currently indirectly interconnected to BPA via IPC and PacifiCorp. This tie would allow SPPCo to increase its import capability rating from 360 to 660 MW. This increase in import capability would improve SPPCo's ability to serve its retail and wholesale customers, and provide SPPCo with more efficiency and flexibility in operating its system. This attribute of the project would also offer economic benefits.

- **Improve Reliability and Security to Customers East of the Tracy Substation.** The Proposed Project would also open up an existing transmission bottleneck into the Reno/Lake Tahoe area. Currently, most of SPPCo's power sources are to the east and the predominant flow is from east to west through Tracy Substation into the Reno/Lake Tahoe area. During high customer demand, the east to west flow on the existing transmission lines are forecasted to become overstressed. This condition could lead to an outage on the transmission system resulting in a disruption of power to the area. The Proposed Project would provide a strong system source on the western side of the system and into the Reno/Lake Tahoe area relieving the stressed condition. This objective would satisfy reliability and performance needs.

  Additionally, the Tracy Substation is a major point source for supply to SPPCo's western customers. Continuing to add supply through this source could eventually jeopardize the security of the electricity supply for customers east of Tracy. A catastrophic event at Tracy Substation or involving one or more of its major elements could result in long-term and wide-spread outages.

- **Provide Additional Access to Pacific Northwest Power Market.** The Proposed Project would increase the access for SPPCo to the Pacific Northwest power market. The increased import capability would allow SPPCo to increase its participation in the NPP where, during the spring and summer, there can be many opportunities to purchase hydroelectric power. This attribute of the project is predicted to offer economic benefits.

The manner in which the primary objectives of the Proposed Project satisfy the needs of SPPCo is discussed in more detail in Sections A.6.4, A.6.5 and A.6.6.

A.6.3.2 Secondary Objectives and Benefits

The Proposed Project offers secondary (or indirect) objectives and/or benefits to SPPCo which are not considered principal justifications of the project, nor do they satisfy critical needs. These are:

- New transmission service
- Export benefits
- Communication benefits
- PG&E upgrade deferrals
- Lassen Municipal Utility District (LMUD) interconnection.

These secondary objectives and benefits of the Proposed Project are discussed in more detail in Section A.6.7.

A.6.3.3 Proposed Project Design

The Proposed Project design has certain features that would accommodate the various objectives and benefits of the project. The project can be divided into four major components, each of which are incorporated into the design of the Proposed Project to satisfy certain project objectives and/or to realize certain benefits.

- 345 kV transmission line
- Alturas Substation
- Border Town Substation
- North Valley Road Substation additions.

SPPCo conducted technical and economic studies to select the optimal voltage level and conductor size for the line. These studies revealed that the optimum voltage is 345 kV. The size of the conductor was determined through engineering analysis. Voltage and system performance were the determining factors for the selection of the conductor. Electrical losses, environmental considerations (such as audible noise and electric and magnetic fields), operations and maintenance considerations were also evaluated.

The amount of power that will be allowed to flow over the Proposed Project is determined by the WSCC study group as discussed in Section A.6.1.2. The maximum capacity of the line will vary and depend on the direction of flow on the Alturas line and the conditions and power flowing throughout the entire WSCC system. The WSCC group has determined that the maximum capacity of the line will be 300 MW. Another important measurement of the Proposed Project is how much import and exports capacity it adds to the SPPCo system. The SPPCo has determined that the Proposed Project will add up to 300 MW of import and export capacity to SPPCo's current capabilities of 360 MW and 0 MW, respectively.

The Alturas Substation would interconnect the project to BPA which would help satisfy several project needs and benefits including: (1) direct access to the Pacific Northwest power market and (2) the benefits associated with operational advantages of being interconnected to the NPP. In addition, this interconnection potentially would have the merit of additional transmission paths to WWP for the proposed merger of SPPCo and WWP (see Section A.6.9.3).

A phase shifter and reactors would be added to the transmission line to control the power flows of the line and enhance the capability of the line, respectively. SPPCo has proposed to install the phase shifter and reactors at the Border Town location because the estimated cost would be approximately $3 to $9 million less than if these components were installed at the North Valley Road Substation. Also, SPPCo believes the Border Town area would provide a convenient location (approximately 12 to 15 miles northwest of Reno) for a substation to accomodate the potential growth in the North Valley area. Additionally, from a system planning standpoint, it is prudent to place the phase shifter as close as possible to the edge of the area to which their control is relevant; Border Town is at the edge of SPPCo's service area. Since SPPCo is expecting growth to the north of North Valley Substation, these new loads should be planned to tie into the SPPCo system south of the phase shifter. The equipment at Border Town is sized appropriately to allow approximately 300 MW of power to flow over the line.

The North Valley Road Substation (located within the City of Reno, near the northwest city limit) was selected as an interconnection point for the project to the SPPCo system because it provides a needed strong second source to the Reno/Lake Tahoe area from the west, satisfying one of the project's primary objectives of improved service reliability to the Reno/Lake Tahoe area. Interconnecting the Proposed Project to the east of the Reno/Sparks area at the Tracy Substation would require substantial upgrades and/or new construction of transmission facilities on SPPCo's 120 kV system west of Tracy, while exacerbating reliability concerns associated with placing the majority of SPPCo's power supply in one corridor (see Section A.6.2.4).

A.6.4 INCREASED IMPORT CAPACITY BENEFITS

Increasing the import capability of the SPPCo system is the most fundamental objective of the Proposed Project. All other SPPCo needs satisfied by the project and benefits of the project result from increasing the import capability or are circumstantial to the project's design. System studies performed by SPPCo and other neighboring members of WSCC show that the import capability of the Northern Nevada Control Area, of which SPPCo is the operator, would increase from 360 MW to 660 MW after operation of the Proposed Project begins (see Section A.6.1.2).

As illustrated on Figure A.6-4, SPPCo is currently interconnected to five neighboring utilities:

- IPC in Idaho
- PacifiCorp (Utah Power & Light) in Utah
- PG&E in northern California
- Los Angeles Department of Water and Power (LADWP) through the IPP in eastern Nevada
- SCE in southern California.

Because of system constraints, SPPCo's import capability is currently limited to 360 MW, even though the sum of the capability of all these interconnections is much greater. Since power flows unconstrained throughout the WSCC grid, all WSCC members must adhere to prescribed local limits to avoid disrupting the system elsewhere. An action by one utility on the grid will affect, at least infinitesimally, all other utilities on the grid. Very complex system analyses are continuously performed and updated by WSCC member groups to ensure that each utility knows the system limits which prevent adverse affects on other members. A set of the limits for each of several system scenarios establishes a control area's ability to import or export power. Individual import levels at the various interconnection points can vary during a set of conditions, but may not exceed the limits set by the WSCC study group.

A set of such limits is a product of the analysis performed by WSCC members participating in the WSCC joint study of the Proposed Project. This group examined several scenarios to determine which system conditions would have the most significant impacts on the operations of existing WSCC utilities' facilities. In the analysis of the Proposed Project, the most critical system condition occurs during light customer demand in the fall and when northern California is importing power from the Northwest.

As other WSCC system changes materialize the import capability rating will be re-determined by the WSCC group evaluating the project between now and when the Proposed Project is approved and constructed. By increasing the import capability, the Proposed Project is expected to provide SPPCo with the following system needs:

- Improve existing inadequate transmission service requirements
- Allow purchases from neighboring utilities
- Respond to long-term emergencies
- Reduce generation reserve requirements.

Improve Transmission Service. Currently SPPCo's import capability is inadequate to meet the requirements of its transmission service customers. Under the 1992 Energy Policy Act, SPPCo is obligated to respond to requests for transmission service from embedded utility customers and attempt to provide the requested service, if feasible. SPPCo is also obligated by California Senate Bill 2431 to seek agreement with all other utilities on the efficient use of the construction of new transmission capacity.

The Proposed Project would provide BPA an alternative wheeling path for service to its customers. Wells and Harney are customers of BPA within SPPCo's control area, and are subject to power interruptions due to limitations on SPPCo's transmission system. Currently, Wells needs 65 MW of transmission services and Harney needs 30 MW . These needs are expected to increase over time as shown in Table A-4. The Proposed Project would accommodate these needs. By having a direct connection between SPPCo and BPA, these BPA customers could purchase transmission service from SPPCo instead of purchasing transmission service from IPC (as is currently done). The agreements and operational feasibility for these potentially less expensive and more direct services have not been fully developed.

Mt. Wheeler Power is also a transmission customer of SPPCo, with present requests for additional service. A recent requested increase of approximately 60 MW of transmission service to serve a large mining customer and the accompanying domestic customers is conditioned with possible interruptions. An increase in import capability would allow SPPCo to provide this service without the interruption clause.

Truckee Donner Public Utility District (TDPUD) has recently contracted with SPPCo for 7 MW of transmission service. The Proposed Project will allow TDPUD to increase its transmission service to 19 MW.

Without the Proposed Project, SPPCo would not be able to serve the increased needs of its existing wheeling customers.

Purchases from Neighboring Systems. The Proposed Project's increase in import capability would also allow additional purchases from neighboring utilities. The greatest benefit from new purchases is projected to be from utilities in the Pacific Northwest (Section A.6.6 expands on this project objective). However, the Proposed Project would allow SPPCo to make additional purchases from neighboring utilities in other areas, including California, Arizona, Utah and other utilities through the interconnected WSCC grid.

Emergency Response. The increase in import capacity resulting from the Proposed Project would also allow SPPCo to respond to long-term emergencies, while adhering to WSCC and the National Electric Reliability Council (NERC) criteria. An extended outage of the Valmy Power Plant is an example of such an emergency. An outage of one of the Valmy generators for several months would cause a major deficiency in SPPCo resources and would likely result in inadequate power supplies, requiring expensive spot market purchases from other utilities. Without adequate power supplies, SPPCo would not be able to meet WSCC and NERC operating criteria, whereas expensive spot market purchases could impact the economic health of the entire SPPCo control area. Through additional access to suppliers, because of the increased import capability, the Proposed Project would result in SPPCo control area operations that meet prudent criteria set by WSCC and NERC, while ensuring the economic integrity of SPPCo's control area.

Reduced Generation Reserves. The increase in import capability provided by the Proposed Project could also mean a reduction in generation reserve requirements. This benefit to SPPCo would equate to reduced costs of planning for and operating generation to maintain WSCC criteria. WSCC criteria call for its members to maintain two types of reserve generation: (1) planning reserves and (2) operating (or spinning) reserves.

Planning reserves are standby generation capacity over and above the demand requirements of a utility that insures an adequate level of service. WSCC calls for its member utilities to plan for reserve generation capacity equal to its largest generation unit, plus five percent of its customer load responsibility. Since the Proposed Project would directly interconnect SPPCo to the NPP, in accordance with WSCC operating criteria, SPPCo could be allowed to eliminate the five percent of its customer load responsibility from reserve requirements. For SPPCo this amount equates to approximately 40 MW of capacity. SPPCo is planning to take advantage of this opportunity to reduce its generation requirements and has conservatively calculated a savings of six to 12 million dollars for the first 15 years of project operation.

WSCC criteria also require member utilities to have standby generation readily available during real-time operations (these are known as spinning reserves). This spinning reserve generation is actually on line, but is not delivering power. It is ready to take on customer load almost instantaneously in the case other supplies fail. The WSCC criteria requires SPPCo to have spinning reserves equal to one half of its largest source, a generator at the Valmy Power Plant. This equates to 69 MW of spinning reserves. With the addition of the Proposed Project, SPPCo could reduce is spinning reserves requirement by again taking advantage of being directly connected to the NPP. WSCC criteria allows two or more control areas to combine or share spinning reserve requirements. By being able to share the largest source requirement with fellow pool members, the spinning reserve requirement could be reduced to a percentage of customer load served. This percentage calculates to approximately 21 MW; therefore the Proposed Project would allow operation at the lower level, saving 48 MW (69 MW minus 21 MW) in spinning reserve. SPPCo estimates this saving in spinning reserves to be worth five to ten million dollars for the first 15 years of project operation.

A.6.5 IMPROVED RELIABILITY AND SECURITY TO THE CUSTOMERS WEST OF TRACY SUBSTATION

SPPCo is experiencing a transmission limitation in the Reno/Lake Tahoe area (Sparks, Reno, etc) west of Tracy Substation which, with forecasted growth in demand, will jeopardize system performance in the summer of 1997. This limitation is created by the existing lines having to transmit increasing amounts of power from major generation sources east of Reno to growing loads in the Reno/Lake Tahoe area. The major resources to the east include the imports from IPC, and the Valmy and Tracy Power Plants.

SPPCo has identified that the Proposed Project would improve service and reliability to the Reno/Lake Tahoe area west of Tracy Substation in three ways:

- Improved system security for customers west of Tracy
- Improved reliability when the East Tracy-North Valley Road 345 kV line is out of service
- Improved voltage control (support during peak periods)

These improvements are discussed in more detail below.

Improved System Security. System security is the ability to withstand various unexpected disturbances. With a large percentage of SPPCo's power supply funneling east to west through Tracy Substation, a major system disturbance at or east of the Tracy Substation could cause extensive possible long-term service disruptions for those customers west of Tracy in the Reno, Lake Tahoe, Sparks and northern valley areas. A catastrophic event occurring at or near the Tracy Substation or along the Tracy-Valmy transmission line corridor such as an explosion, fire, or some sort of natural disaster could cause long-term supply problems for customers west of the Tracy Substation. These problems could have adverse economic, health, and/or safety implications resulting from long-term power supply shortages to a large urban area. As customer demand increases west of Tracy, and if additional resources are channeled through Tracy Substation, SPPCo system security could worsen. The Proposed Project would provide an additional supply source which would improve system security for these customers in case of a catastrophic event.

Improved Reliability. The primary transmission line into Reno transmitting power from the eastern resources is the 345 kV line from East Tracy Substation to North Valley Road Substation. In addition to this primary 345 kV line, there is a network of smaller 120 kV lines that also transmit power into Reno from the east. When the East Tracy-North Valley Road 345 kV line is out of service, the other smaller lines must be able to carry the additional burden to serve the Reno/Lake Tahoe area to adhere to SPPCo's reliability criteria. This criterion prohibits allowing a potential condition in which an outage of one line causes another line to be overloaded. The 120 kV line extending from Tracy Substation to Spanish Springs Substation is projected to exceed its design power carrying capability (current rating) with an outage of the 345 kV line by the summer of 1997. If uncorrected, this condition could cause damage to the line, or to avoid line damage it could result in an interruption of service to the Reno/Lake Tahoe area.

One solution to this problem would be to build additional transmission from the east into Reno. However, as previously discussed (improved system security), this solution does not compare favorably to the Proposed Project, which would solve the problem in a different way. The Proposed Project would provide a source of power to the Reno area from a different direction: it would tie into the North Valley Road Substation from the northwest and provide a source of emergency power imports from the NPP during emergencies such as the outage described above. This emergency power supply could be utilized under pool agreements to serve loads in the Reno/Lake Tahoe area during the potential outage, offsetting power flowing from the eastern resources, long enough to restore the outage. This contingency condition would occur when no power was being transmitted on the Proposed Project.

If SPPCo happened to be importing power on the Proposed Project during the above described disturbance, the power flowing on the lines into Reno from the east could be relatively low due to the supply from the Proposed Project offsetting flow from the east. In this case the outage of the 345 kV East Tracy-North Valley Road line may not require emergency actions.

The need for a second strong source west of Tracy is one objective which is driving the timing of the Proposed Project. SPPCo power flow analysis for the system, with the most current load forecast and generation plan, shows that this potential overload contingency can occur in the summer of 1997. Therefore, the Proposed Project would need to be in service before SPPCo's summer peak, which can occur as early as June.

The alternative to the Proposed Project to provide this needed reliability enhancement would be to build or upgrade additional transmission lines. A 120 kV line from East Tracy Substation (approximately 15 miles east of Reno) to Silver Lake Substation (located northwest of Reno in the North Valley area) would alleviate the overload contingency and cost $9.1 million. A 345 kV line from East Tracy to Silver Lake would also solve the problem for $24.1 million. These lines would also satisfy the need for additional service into North Valley. However, these transmission facility additions would not increase the import capacity of the SPPCo system, improve system security for customers east of Tracy, or provide additional access to the Pacific Northwest power market.

Voltage Control. The Proposed Project would also help maintain voltages at prescribed levels in the Reno/Lake Tahoe area. In order to maintain system voltages at prescribed levels, reactive power must be altered as demand fluctuates. Reactive power is a component of power production that is not sold, but is critical to the operation of an electrical system. By increasing the reactive power supply to an area, voltages levels can be bolstered or supported. Conversely, by decreasing the reactive supply, voltage levels can be brought down. During peak loads, the transmission of reactive power from generation plants can be very inefficient, resulting in voltage decline. Capacitors can be installed closer to the loads and supply needed support in areas where reactive power is deficient. The Proposed Project would provide a needed source of reactive power support in the Reno/Lake Tahoe area during the contingency outage of one of the 345 kV Valmy-East Tracy transmission lines. SPPCo could avoid installing capacitors in the Reno/Lake Tahoe area as a result of the Proposed Project and save approximately $1.5 million. This need is expected to arise sometime between the years 2000 and 2008.

A.6.6 ACCESS TO MORE ECONOMICAL POWER MARKETS

The Proposed Project would increase SPPCo's access to the Pacific Northwest and other economic spot or economy energy markets. By directly interconnecting to the NPP, combined with the increase in import capability discussed in Section A.6.4, SPPCo would be able to increase its participation in the NPP where there can be many opportunities to access relatively inexpensive hydroelectric power supplies during the spring and summer, depending upon the transmission capacity available on the BPA 230 kV line. Depending on regional need and availability, spot market power could come from any area. This attribute of the project enhances the economic benefits of the Proposed Project.

Since BPA transmits power generated by hydroelectric facilities in the Pacific Northwest, the most direct access to this hydroelectric power is through a direct interconnection to the BPA system. Indirect interconnections to BPA through IPC, PacifiCorp via the Utah intertie, and others would not provide the same degree of access to this power market as would the Proposed Project, since wheeling charges would be incurred (IPC, PacifiCorp, etc. would charge SPPCo for the transport of power on their systems) and transmission capacity may not be as readily available.

The project would be expected to increase SPPCo's import capability from 360 to 660 MW. This increased capability could be fully or partially utilized throughout the year to purchase power from NPP members through one of three types of purchases:

- Non-firm purchases
- Short-term firm purchases
- Long-term firm purchases.

Non-Firm Purchases. Non-firm purchases are made through agreements in which power deliveries have limited or no assured availability. A non-firm purchase might come from a hydroelectric power supply in the years where there is an abundance of water supply from precipitation. This power cannot be guaranteed for delivery on a continuous basis. The Pacific Northwest, with its predominant hydroelectric power base, can be a significant market for non-firm purchases.

Many opportunities for non-firm purchases are expected to be available from less expensive sources through the additional import capability supplied by the Proposed Project. SPPCo estimates cost savings of between $5 to $33 million as a result of non-firm economy energy purchases for the first 15 years of the project operation.

Firm Purchases. Firm power purchases are contracted, either on a short- or long-term basis, and are intended to have assured availability to the purchaser. Long-term purchases of power are made under contracts extending for several years. Currently, SPPCo is using its 360 MW import capability to purchase 262 MW from PacifiCorp, IPC and Tri-State G&T. These purchases are long-term and have the terms as shown in Table A-6.

Table A-6 Long-Term Power Purchases by SPPCo

Supplier	Amount of Purchase	Contract Expiration
Idaho Power Company	90 MW	1999
PacifiCorp	74 MW	2021
PacifiCorp	75 MW	2009
Tri-State G&T Coop	23 MW	2008
TOTAL	262 MW	

As these long-term contracts run out and SPPCo's load growth introduces the need for more long-term purchases, SPPCo will look to less expensive sources. Increased access to more sources enhances the opportunity for savings.

During the summer and winter peak load periods, SPPCo purchases short-term (from one week to a few months) in order to maintain its operating reserve requirements. Again, increased access to more short-term sources enhances SPPCo's opportunity for savings.

SPPCo estimates savings of between $6 to $46 million in firm purchases as a outcome of access to additional power markets resulting from the Proposed Project for the first 15 years of project operation.

A.6.7 SECONDARY OBJECTIVES AND BENEFITS

The Proposed Project would offer other secondary or indirect benefits to SPPCo which are not considered principal justifications of the project, and would not satisfy critical needs. These are:

- New transmission service
- Export benefits
- Communication benefits
- PG&E upgrade deferrals
- LMUD interconnection.

A.6.7.1 New Transmission Service

In addition to the immediate transmission needs of Wells, Harney, TDPUD and Mt. Wheeler, discussed in Section A.6.4, SPPCo has identified other potential transmission service (wheeling) needs. PG&E is expected to request to transmit power into SPPCo's area (wheeling-in services) to LMUD, if the LMUD interconnection is built. PacifiCorp, Nevada Power Company, and SCE have each inquired about wheeling through the SPPCo system. Independent power producers are also expected to request wheeling services within, outside and into the SPPCo system. The value of these services has not been estimated, but the need for these wheeling-in, wheeling-out and wheeling-through services is estimated to be between 150 to 400 MW, including the services that are immediately needed. Currently, SPPCo's transmission capabilities are inadequate to meet the requests of these potential transmission service customers.

A.6.7.2 Export Benefits

SPPCo expects to realize savings from the Proposed Project by avoiding import purchases required when IPC is taking power from the Valmy Power plant on the SPPCo system. To stay within their operational limit, SPPCo must import power while power from Valmy is being transferred to IPC. These import purchases are sometimes more expensive than the cost of SPPCo generating the power itself. SPPCo estimates the first year costs of these import purchases to be almost $900,000 more expensive than self-generation. The Proposed Project is expected to eliminate the need to import power while power is being transferred to IPC and result in a $5 to $20 million savings over a fifteen-year period.

A.6.7.3 Communication Benefits

The communication systems, which are a part of the Proposed Project's design to provide remote control of substation equipment, would also provide improved control and communication functions between the Northwest Control Area and SPPCo's Control Area. This feature would increase reliability and improve operations of both control areas.

A.6.7.4 PG&E Upgrade Deferrals

Currently, SPPCo must compensate PG&E for certain improvements on the PG&E system as PG&E customer loads grow, or SPPCo loses some of its ability to import power over the PG&E interconnection. SPPCo began upgrades to the 120 kV PG&E intertie in 1991. Two upgrades have been completed to date, and one is scheduled for completion in 1996. A plan for the PG&E improvements through the year 2002 has SPPCo funding four separate upgrades to the PG&E system as shown in Table A-7. SPPCo speculates that these upgrades could be deferred or delayed with the Proposed Project, although no specific studies have been done to verify savings from these deferrals.

Table A-7 SPPCo Potential Payments for PG&E Upgrades

Year	Improvement Type	Estimated Cost (Millions)	
		Low	High
1998	Transformer addition	$9	$9
2000	Line re-conductor	$11	$14
2001	Line re-conductor	$3	$4
2002	Transformer addition	$8	$10
	Totals	$31	$37

A.6.7.5 Lassen Municipal Utility District Interconnection

LMUD is a publicly owned and operated utility in Lassen County, California, which has requested transmission service from SPPCo for access to power markets outside their service territory. LMUD has entered into a memorandum of understanding (MOU) with SPPCo, reserving 50 MW of transmission service on the Proposed Project, if the project is approved. A potential location for the future interconnection is Wendel, California. Studies have not been performed to investigate the physical effects that a LMUD interconnection would have on the Proposed Project, but SPPCo anticipates no adverse impacts. In accordance with the MOU, LMUD would be responsible for all planning, design, construction, and operation costs.

A.6.8 ALTERNATIVE SOLUTIONS TO THE PROJECT'S PURPOSE AND NEED

As required by CEQA and NEPA, this EIR/S considers several alternatives to the Proposed Project. Sections B.3 and B.4 provide detailed descriptions of these alternatives and the alternative screening rationale. This section describes how, and to what degree, each of the alternatives considered would satisfy the objectives of the Proposed Project. The environmental impacts of the alternatives are discussed in Part C.

Alternatives which have been considered in this EIR/S to satisfy some of the objectives and/or provide some of the benefits of the Proposed Project can be grouped into three categories: (1) Transmission Alternatives, (2) Generation Alternatives and (3) System Enhancements Alternatives. A summary of how these alternatives satisfy the project objectives is presented in Table A-8. The table also shows the estimated cost of each alternative, the improvement in total import capability, and the relative cost per kilowatt for improvements in import capability.

A.6.8.1 Transmission Alternatives

With the exception of Tracy-North Valley Alternatives, all of the transmission alternatives that have been considered would provide improved import capability. The alternatives which interconnect with utilities in the NPP would generally offer more benefits, since SPPCo, as a NPP member, can take advantage of reserve sharing and diversity of resource needs.

Table A-8 Summary of Project Alternatives Versus Project Objectives[a]

ALTURAS PROJECT OBJECTIVES	PROJECT ALTERNATIVES (Numbers in parentheses refer to footnotes below which provide descriptions of the alternatives.)													
	TRANSMISSION ALTERNATIVES									GENERATION ALTERNATIVES		SYSTEM ENHANCEMENT ALT.		
	Mdpt Valmy #1 (1)	Mdpt Valmy #2 (2)	Pacific DC Intertie (3)	Southern Ties (4)	LADWP Corridor (5)	Burns-Oreana (6)	French-man Tap (7)	Utah Intertie (8)	Tracy-N.Valley (9)	Piñon Power (10)	CT (11)	Series Comp (12)	DSM (13)	Cap. Banks (14)
INCREASED IMPORT CAPACITY														
Fulfill Existing Inadequate Transmission Service Requirements	Y	Y	U	P[b]	Y	Y	P	N	N	N	N	N	N	N
Allow Purchases from Neighboring Utilities	Y	Y	Y[b]	Y	Y	Y	Y	Y	N	N	N	N	N	N
Respond to Long-term Emergencies	Y	Y	Y	P[b]	Y	Y	P	N	N	P[b]	P[b]	N	N	N
Reduced Generation Reserves Requirement	Y	Y	Y	Y[b]	Y	Y	P[b]	P[b]	N	N	N	N	N	N
IMPROVED SYSTEM SECURITY AND RELIABILITY WEST OF TRACY														
Improved System Security for Customers West of Tracy	N	N	N	P[b]	Y[c]	N	N	P	N	N	P[b]	N	N	N
Improved Reliability for Customers West of Tracy	N	N	N	P[b]	Y[c]	N	N	P	Y[c]	N	P[b]	N	N	N
Improved Voltage Control (Support During Peak Periods)	U	U	U	N[b]	Y	U	N	N	Y[b]	N	N	N	N	Y
Transmission Service Facilities for New Customers in the North Valley	N	N	N	N[b]	N	N	N	N	Y	N	N	N	N	N
ACCESS TO THE PACIFIC NORTHWEST POWER MARKET														
Direct Access to BPA	N[b]	N	Y[b]	N	Y[d]	N	N	N	N	N	N	N	N	N
Access Through Other Utility[f]	Y	Y	N	U	Y[e]	Y	N	P[b]	N	N	N	N	N	N
SECONDARY OBJECTIVES AND BENEFITS														
New Transmission Service	Y	Y	Y[d]	Y	Y	Y	U	P[b]	N	N	N	N	N	N
Export Benefits	Y	Y	Y	Y	Y	Y	U	U	N	N	N	N	N	N
Communication Benefits	P[b]	P[b]	U	Y[b]	P[b]	P[b]	N	N	N	N	N	N	N	N
PG&E Upgrade Deferrals	Y[b]	Y[b]	Y[b]	U	Y[b]	Y[b]	U	U	N	N	N	N	N	N
LMUD Interconnection	N	N	N	N	N	N	N	N	N	N	N	N	N	N
COST COMPARISON[g]														
Estimated Cost ($ Million)[h]	80	80	128	66-153	220[e]	215	20	47-96	9-24	186[i]	U	6	U	1.5
Import Capability Improvement (MW)[h]	350	300	400	225	300-350	350	100	20-50	NI	NI	NI	35	NI	NI
Proportional Improvement ($/kW)	229	267	320	293-680	628-733	614	200	1100-2500	NI	NI	NI	170	NI	NI

Note: key to table on following page.

Notes for Table A-8

Cell Entries:

Y= Yes, expected to reasonably satisfy objective or provide stated benefit; reasonable satisfaction does not necessitate 100% satisfaction.

N= Not expected to satisfy objective or provide stated benefit beyond an insignificant increment.

P= Objective or benefit expected to be partially satisfied.

U= Data unavailable to make any assessment

NI=No import capability

Alternatives:

1 Integration with the IPC Southwest Intertie Project via a Midpoint-Toano 500 kV/Toano-Carlin-Valmy 345 kV interconnection.

2 Proposed 345 kV transmission line from IPC's Midpoint Substation to SPPCo's Valmy Power Plant, via the Carlin area.

3 Interconnection to the LADWP operated Pacific Northwest-Pacific Southwest DC Intertie.

4 Interconnections to Nevada Power Company south of SPPCo. Costs in 1987 dollars.

5 Two transmission alternatives traveling within the LADWP DC corridor with connection east the North Valley Road Substation; the Nevada Alternative would originate in east Alturas (no cost data available) and the Summer Lake-Valley Road Alternative would originate at PacifiCorp's 500 kV Summer Lake Substation.

6 Interconnection from the SPPCo Oreana Substation to IPC at the Burns Substation.

7 Interconnection of SPPCo's Fort Churchill-Austin 230 kV line with SCE's 230 kV line extending to the Oxbow Geothermal generating facilities within SPPCo's service area.

8 Enhancement to the 230 kV interconnection to UP&L, which include 230 or 345 kV line additions or improvements along the Fort Churchill-Gonder corridor.

9 A 120 kV line from East Tracy Substation to Silver Lake Substation at a cost of $9.1 million or a 345 kV line from East Tracy to Silver Lake at a cost of $24.1 million.

10 The proposed 95 MW Integrated Gasification/Combined Cycle Piñon Project is being developed jointly with the U.S. Department of Energy. This project is included in SPPCo 1993 Electric Resource Plan and is included among these alternative to demonstrate its contribution to the Proposed Project's objectives.

11 Proposed Fort Churchill Combustion Turbine.

12 The addition of series compensation (capacitors installed in series with a transmission line) on the 230 kV line that interconnects SPPCo with IPP and UP&L.

13 Demand Side Management.

14 The installation of capacitors in the Reno/Lake Tahoe area.

Superscripts:

a Alternative segments to the alignment of the Proposed Project are not considered since they would not affect the ability of the Proposed Project to achieve the project objectives.

b No conclusive studies or data is available to verify the assessment.

c While the alternative could technically satisfy the objective, the feasibility of the alternative is subject to existing land use constraints. Since the alternative would need to traverse an urbanized area (City of Sparks and northern Reno area) and given the inadequate width of existing powerline corridors, the feasibility of the alternative is highly questionable. (See Section C.14 for a complete discussion.)

d Yes, Nevada Alternative only.

e Yes, Summer Lake-Valley Road Alternative only.

f The Proposed Project would provide SPPCo with direct access to the Pacific Northwest Power Market. Additional charges would be incurred if access to the Pacific Northwest Power Market required wheeling through neighboring utilities.

g The estimated cost for the Proposed Project is $120 million with an expected improvement in import capacity of 200 - 300 MW; resultant proportional improvement would be $400-600/kW.

h Many of the values in this table are rough approximations developed by SPPCo for comparison purposes only. It should be noted that the estimates come from a wide range of studies, all with different assumptions; therefore, comparisons should be made with discretion. In the case of SWIP, Midpoint-Valmy and Pacific DC Intertie, costs represent SPPCo's estimated share and are subject to negotiations and interpretation by others. Cost estimates are in 1993 dollars or as designated in the footnotes. Most values are pending review of additional information requested from SPPCo.

i 50%, or $93 million, of construction costs to be incurred by the Department of Energy.

The alternatives which interconnect with utilities in the NPP would also, in most cases, provide improved access to the Pacific Northwest power market. Since BPA transmits power generated in the Pacific Northwest, the most direct access to the spot, economic NPP energy market (e.g., hydroelectric) is through a direct interconnection to the BPA system. Therefore, interconnections to IPC, PacifiCorp via the Utah intertie, and others would not provide the same degree of access to this power market as the Proposed Project since wheeling through the noted utilities would be required. Only the Nevada Route Alternative would be directly connected to BPA.

Only those transmission alternatives which tie into the Reno area would satisfy the Proposed Project objective of providing improved reliability and improved system security for those customers west of Tracy Substation. The dominant strong source of power supply now comes over the 345 kV corridor from IPC, the Valmy Power Plant and the Tracy facilities. Many of the alternatives, such as the Midpoint-Valmy and Burns-Oreana Alternatives, would utilize this corridor and therefore, place even more of SPPCo supply on the corridor, exacerbating the current reliability condition.

A.6.8.2 Generation Alternatives

Generation alternatives could not provide direct access to the Pacific Northwest power market or directly improve import capability. However, generation additions at the proper locations could provide improved service reliability to the Reno/Lake Tahoe area. For instance, a generator located at the North Valley Road Substation might remedy the reliability problem in the Reno/Lake Tahoe area. Further, if the generation addition was an inexpensive source of power, it could diminish the benefit of access to inexpensive power in the Pacific Northwest. However, it is unlikely that new generation could compete with the inexpensive sources in the Northwest since the cost per kilowatt for native generation is expected to be substantially higher than Pacific Northwest hydroelectric power. This assumes prices will compare as they have historically and that the supplies in the Pacific Northwest will continue at current levels.

SPPCo is currently pursuing the addition of three new native generation projects: the Piñon Pine Power Plant, Fort Churchill Combustion Turbines, and the Greenfield Project (the Piñon Pine Power Plant and Fort Churchill Turbines are described in Section B.3.4.3; the Greenfield Project is described in Section E.3.3). Since the Piñon Pine Power Plant (currently under construction) is to be located at Tracy, it would place more supply on the Tracy-North Valley corridor. As a result, this generation project would not improve service reliability west of Tracy. Since the Fort Churchill Combustion Turbines would be located to the south of the Reno/Lake Tahoe area, avoiding the Tracy-North Valley corridor, they would improve service reliability. A site has not been selected for the Greenfield Project. The Fort Churchill and Greenfield projects are not scheduled to be completed until after 1998 and may be deferred if additional power purchases can be obtained with the Proposed Project, or through the proposed merger with WPP. None of the generation additions which have been considered by SPPCo would have the characteristics or timing to satisfy all of the objectives or offer the economic advantages of the Proposed Project.

A.6.8.3 System Enhancement Alternatives

System enhancement alternatives could indirectly satisfy some of the project objectives. The addition of series compensation (capacitors installed in series with a transmission line) on the 230 kV line that interconnects SPPCo with IPP and Utah could improve electrical system performance, resulting in improved import capability. But the level of improvement would be much less than that of adding a 345 kV interconnection. The installation of capacitor banks in the Reno/Lake Tahoe area would only improve the voltage performance in that area.

SPPCo has planned and implemented Demand Side Management (DSM) programs. DSM measures are designed to reduce energy consumption and the need for new generation. DSM lessens the burden of the entire system, and therefore, reduces the need for all types of utility services and indirectly alleviates the reliability concerns. As a result and to a certain degree, DSM satisfies many of the Proposed Project's objectives. However, DSM alternatives cannot offer the same magnitude of benefits as the Proposed Project (see Section B.3 for complete discussion). DSM measures implemented and planned by SPPCo have been taken into account in the ERP process assessing the need for the Proposed Project.

A.6.8.4 Alternative Combinations

Combining two or more of the alternatives described above has also been considered in the alternative analysis. The primary objectives of the Proposed Project could be met, at least partially, by combining two or more alternatives. However, combining alternatives would not satisfy all secondary benefits and objectives of the Proposed Project. For instance, combining the East Tracy to Silver Lake 345 kV transmission alternative with the Midpoint to Valmy alternative would largely satisfy the primary objectives, but would not allow a future interconnection with LMUD. Further, even though this combination would accommodate the Pacific Northwest access and interconnection, it would not afford the benefits of a direct interconnection with BPA that the Proposed Project would provide (see Section A.6.6) nor would it provide improved system security for customers east of Tracy Substation (see Section A.6.5).

A.6.9 IMPLICATION OF THE PROPOSED PROJECT FOR SPPCo AND OTHER UTILITIES SYSTEMS

A.6.9.1 BPA Operations

BPA is a power marketing agency within the U.S. Department of Energy. BPA's primary service area is the Pacific Northwest, including Oregon, Washington, Idaho, western Montana, and small parts of Wyoming, Nevada, Utah, California and eastern Montana. BPA also sells or exchanges power with utilities in California and Canada. BPA was established in 1937 as the marketing and transmission agent for power produced by the Bonneville Dam. Congress gave BPA the responsibility to supply electrical power to its utility, industrial, and other customers in the Pacific Northwest. Congress also directed BPA to build and operate high-voltage transmission lines to move electric power from hydroelectric dams, and generation plants fired by many types of fuel.

Today BPA markets power from 31 Federal dams and one nuclear plant. BPA owns and operates over 15,000 miles of transmission lines in the Pacific Northwest. These transmission lines are used by both public and private electric utilities to transmit and market power throughout the region. Almost half of all of the power used in the Northwest comes from BPA, and BPA provides about three-fourths of the region's transmission capacity. About 85 percent of the power BPA sells is hydroelectric.

SPPCo currently delivers BPA power to BPA (Wells, Harney) and Mt. Wheeler Power loads embedded within the SPPCo control area. As these loads have grown, SPPCo's existing limited import capabilities has resulted in inadequate service to these loads (see Section A.6.4). With the Proposed Project, BPA would be able to contract for more reliable service since the import capability of the SPPCo system would be increased.

The Proposed Project's Alturas Substation would also interconnect SPPCo directly to BPA. BPA power deliveries to SPPCo are currently made through the IPC and PacifiCorp systems. This direct interconnection to SPPCo could potentially give BPA closer and less expensive access to those customers within the SPPCo area by avoiding transmission service through IPC and PacifiCorp. However, agreements would have to be negotiated to realize this added benefit to the BPA customers.

The Proposed Project would also give SPPCo access to BPA's hydroelectric power during the spring and summer months, when available, assuming prices will compare as they have historically, and that the supplies continue at historical levels. BPA transmits hydroelectric power that is currently generated along the main stem of the Columbia and Snake Rivers and several major tributaries. The impacts of existing hydroelectric generation and operation alternatives are currently being evaluated by the Corps of Engineers, Bureau of Reclamation, and BPA. These Federal agencies are jointly preparing a System Operation Review (SOR) EIS on the operation of the Columbia River hydroelectric system. Impacts being addressed by the SOR EIS include navigation, flood control, recreation, hydropower generation, fish and wildlife, and irrigation.

Major changes in Columbia River system operations are being considered. Decisions regarding operation of the Columbia and Snake systems will take into account both power and non-power uses of the river system. For example, minimum flows and pool levels in the various reservoirs will be made through SOR to enhance and protect endangered salmon species. As part of the development of a multiple-use operating strategy for the hydroelectric system, the SOR EIS will evaluate the trade-offs between power and non-power uses. Balancing the multiple uses of the Federal hydroelectric facilities in the Columbia River Basin could affect hydroelectric power production. The Alturas Transmission Line would not affect or change in any way these river operation agreements. If a System Operating Strategy is adopted that causes a reduction in hydroelectric power operation or capability, BPA could need to acquire alternate resources. This, in turn, could affect the availability of low cost hydroelectric power for SPPCo. The potential for development of additional generation sources in the Pacific Northwest if hydroelectric supply decreases is discussed in Section E.3.3.

If the SOR reduces the availability of hydroelectric power, this would negate the benefit of possibly purchasing low-cost power. Other benefits, such as those associated with reserves, system security and reliability would be unaffected.

The Draft SOR EIS was released for public comment in July, 1994. The Draft EIS did not identify a preferred system operation alternative. The close of the comment period was scheduled for December 15, 1994. The Final SOR EIS is scheduled for release in December, 1995.

The BPA system in the vicinity of the northern termination of the Proposed Project has been analyzed by the WSCC study group. The study group identified operational procedures and facility installations (capacitors) in the area to improve the import capacity. The Proposed Project would not adversely affect the ability to serve load in the area.

A.6.9.2 Valmy Power Plant Operation

The Valmy Power Plant is a coal-fired steam plant which is SPPCo's largest generation resource (269 MW). The plant is half owned by SPPCo and half owned by IPC. The Proposed Project would decrease SPPCo's dependance on Valmy for system reliability, and allow greater operational flexibility and more economic operation of the plant.

Currently SPPCo operates with a risk of not being able to serve its customers with adequate reliability if there were a long-term loss of the Valmy plant. The Proposed Project would improve import capability, thus providing additional replacement options for a potential long-term outage of the plant.

SPPCo cannot currently export power from its control area because of potential system instability. Since the Valmy Power Plant is within SPPCo's system and SPPCo must transfer IPC's share of the generated power, SPPCo must also import power to insure a zero net export. SPPCo imports power much of the time, but the cost of such imports can vary greatly depending on the availability. There are times where SPPCo can generate power internally at a lower cost than it can import power. The Proposed Project would allow SPPCo to export IPC's share of generated power without having to pay for the higher cost imports.

A.6.9.3 Proposed SPPCo and Washington Water and Power (WWP) Company Merger

SPPCo and WWP in Spokane, Washington, have proposed a merger of their two utilities. SPPCo has projected supplementary savings from the Proposed Project relative to this potential merger which have a present value of $77 million. These savings would arise from sharing in the more efficient operation of generation resources for serving loads. In addition, savings would result from the planning and operation of combined reserve generation. Finally, SPPCo would gain additional economic opportunities for firm resource purchases through WWP.

The merger between SPPCo and WWP is currently undergoing an extensive approval process before the merger can be realized. The entire approval process is expected to take approximately 13 months; the procedural merger of these two utilities began in October 1994. Filings for the merger have already been made with the five affected States (Nevada, Washington, California, Idaho, and Oregon), and the Federal Energy Regulatory Commission (FERC). The two companies have received the approval of their respective stockholders. The approval process involves a series of Prehearing Conferences, Consumer Sessions, filings of testimony, hearings, and will result in decisions from the five State Public Service Commissions. In addition, approval must be obtained from FERC.

SPPCo has negotiated for two separate paths to make exchanges with WWP. One through BPA's system allows up to 90 MW of power to be transmitted from WWP to SPPCo and up to 200 MW from SPPCo to WWP. This path will require the completion of the Proposed Project. The other path, through IPC's system, will allow for a maximum of 100 MW from WWP and a maximum of 50 MW to WWP. This additional use of import capability (190 MW) is not expected to impact the other proposed uses or benefits of the Proposed Project.

The Proposed Project and the merger with WPP are complementary to one another in realizing certain benefits associated with increased import capacity. For instance, the deferral of SPPCo planned resources discussed in Section A.6.2.2 is possible with the Proposed Project's increased capability to import firm resources and is more likely with the potential integration of resources with WPP. Likewise, the sharing of generation reserve requirements are more plausible with the merger, than without.

A.6.10 GLOSSARY OF TECHNICAL TERMS AND ACRONYMS

[Note that a more complete Glossary is included in Appendix A.]

BPA
Bonneville Power Administration

Capacity
The power ability of electrical equipment measured in watts.

Control Area
A portion of the interconnected electricity system grid whose operations and procedures are controlled and managed by a single utility. This utility typically owns most of the facilities in its control area and is responsible for the physical interaction with neighboring control areas.

DSM
Demand Side Management, for example, home insulation, energy efficient appliances, etc.

ERP
Electric Resource Plan, required by the Public Service Commission of Nevada every three years.

Export Capability
The capacity or extent to which a utility or electric control area can sell electric power outside its electric system at a given time or during a given set of conditions using all available facilities.

Exports
The sale of electricity by a utility to another utility outside its electric system.

Firm Purchases
Contractual procurement of electric energy which is intended to have assured availability to the customer.

Generation
The production of electricity from other forms of energy such as combustion, falling water or thermal transfer.

Generation Capacity
Maximum electric production limit for which a generator is rated. The maximum limit fluctuates with changes in temperature or other environmental circumstances, depending on the type of machine.

gWh
Gigawatt-hours. A measure of electric energy. One million kilowatt-hours.

Harney
Harney Electric Cooperative, Inc.

Import Capability
The capacity or extent to which a utility or electric control area can purchase electric power from outside its electric system at a given time or during a given set of conditions using all available facilities.

Imports
The purchase of electricity by a utility from another utility outside its electric system.

IPC
Idaho Power Company

IPP
Intermountain Power Project

IRP
The 1995-2014 Electric and Gas Integrated Resource

kV
Kilovolt. A measure of electric voltage, one thousand volts. Household current is supplied at 120 volts.

LADWP
Los Angeles Department of Water and Power

LMUD
Lassen Municipal Utility District

Load Centers
Major areas of electricity consumption such as large cities or large industrial facilities.

MW
Megawatt. A measure of electric power. One thousand kilowatts or one million watts. A standard light bulb is 60 - 100 watts.

Native Generation
Electricity generation within a utility service area.

NERC
National Electric Reliability Council

Non-firm Purchases
Electric energy purchases having limited or no assured availability.

Non-utility Owned Generation
Generation which is possessed by an entity not in the business for the sale of electricity at retail.

NPP
Northwest Power Pool

Operating (or Spinning) Reserves
As required by WSCC Operating Criteria, WSCC member utilities must have standby generation, actually on-line, but not delivering power, to insure an adequate level of service.

PG & E
Pacific Gas and Electric Company

Planning Reserves
As required by WSCC Operating Criteria, WSCC member utilities must have standby generation capacity, in addition to existing demand requirements, to insure an adequate level of service.

Pool Agreements
Agreements among utility alliance members (e.g., NPP) for the sharing of resources or satisfaction of operation and reliability criteria.

Power
The time rate of transferring energy (expressed in watts).

PSCN
Public Service Commission of Nevada

Rating
Maximum operation limit of transmission or generation facilities, as established by WSCC and/or NPP operating and reliability criteria guidelines. Utility facilities and interconnections can be rated either for individual or simultaneous operation, where simultaneous operations take into consideration collective WSCC or NPP utilities.

Reactive Power
A component of power production that is not sold.

SCE
Southern California Edison Company

Self-owned or Utility-Owned Generation
Generation which is possessed by a utility.

SOR
System Operation Review for BPA hydroelectric power generation operations.

SPPCo
Sierra Pacific Power Company

System Security
The ability of the bulk power electric system to withstand sudden disturbances such as an electric short circuit of unanticipated loss of system components.

TDPUD
Truckee Donner Public Utility District

Transmission Service Customers
Wholesale electricity utilities or other entities which pay for the use of another utility's facilities to transmit electric power from one point to another.

USFS
U.S. Forest Service

Wells
Wells Rural Electric Company

Wheeling
An electric operation wherein transmission facilities of one system are utilized to transmit power of another system. Power can be wheeled in, through, or out of a utility system.

WSCC
Western States Coordinating Council

WWP
Washington Water and Power Company

A.7 REFERENCES

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